Western States Petroleum Association
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President

February 17, 2015

Clerk of the Board, Air Resources Board,
1001 I Street,
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http://www.arb.ca.gov/lispub/comm/bclist.php

Re: **Public Hearing to Consider a Low Carbon Fuel Standard (LCFS) – Board Agenda Item 15-2-4**

The Western States Petroleum Association (WSPA) appreciates the opportunity to submit written comments for the record on the above proposed rulemaking. WSPA is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and four other western states.

WSPA members hold the compliance obligation under the LCFS and are responsible for the challenging job of producing the vast majority of the transportation fuels used daily in California. WSPA has been engaged in the rulemaking process to develop and implement the LCFS since 2007. We have continued to make technical comments on updated regulatory packages and changes to the program despite our concerns about the overall feasibility of the LCFS program.

The fundamental problem with the LCFS remains that it is not good public policy and is incorrectly structured in its reliance on the emergence of a significant low carbon fuels market. We do not see anything in the regulatory package to change our assessment that the LCFS program and compliance schedule will remain infeasible when reauthorized.

A government agency such as ARB should not be setting goals that are aspirational and unrealistic, and then following up with band aid measures that make compliance easier while the market waits for low carbon intensity (CI) fuels to be produced at commercial volumes. The fact that a multitude of credit generation options and a cost containment provision are being proposed for inclusion in the program is a signal reflective of the program's fundamental problems.

In our view, the current 1% CI reduction freeze has given all stakeholders and ARB an opportunity to reflect on what has worked, and particularly what has not worked within the LCFS. As ARB has admitted frequently, the development of commercial–scale low CI fuels, such as cellulosic ethanol, has been much slower than originally envisioned. We must take this re-adoption effort as an opportunity to assess the true status of low CI fuel production, infrastructure, vehicle availability, and consumer acceptance (not aspirational projected or nameplate capacity estimates) and make the changes necessary for an effective program. Additional research and development needs to occur before we can transform to a low CI fuel system.

At its core we believe the LCFS, as envisioned by Governor Schwarzenegger in his original Executive Order and as currently designed, is infeasible. Although there will continue to be a slow shift in the transportation fuels market, staying the course with the current design of the program could result in disruptions in the transportation fuels market. There needs to be recognition that California consumers depend on and expect a reliable, useable, and scalable fuel source based on the vehicle population and fuels infrastructure in existence now.

A successful climate-oriented fuels policy must protect against fuel supply disruptions, severe job losses in the state's refining industry and unacceptable economic harm to California and its citizens. WSPA and its members are committed to engaging with you to find better, achievable ways of reducing carbon emissions from transportation fuels.

<u>WSPA Requests</u>

WSPA requests two main items of ARB relative to the effort to reauthorize the program. We also have a number of more specific recommendations and requests in our detailed comments that follow. In short:

- WSPA requests program reviews that culminate in staff reports to the Board on an annual basis.
- WSPA requests no further efforts to create post-2020 LCFS reduction targets until the pre-2020 program is a proven, feasible program.

Sincerely,

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Western States Petroleum Association Comments on CARB's Public Hearing to Consider a LCFS – February 19, 2015

General Comments

1. Current Program Status and Proposed Compliance Targets

Since its inception, the LCFS program has aspired to deliver a 10% reduction in California motor fuel carbon intensity by 2020 versus the 2010 baseline year. Over the same period, WSPA questioned the program's viability pointing out that ARB is relying on as-yet to be developed novel technologies to supply the low CI fuels necessary to meet this goal. WSPA also questioned whether the timetable for the emergence of such technologies (primarily cellulosic fuels) would coincide with ARB's projections. To date, ARB staff has maintained that the LCFS program is working as intended, but WSPA remains concerned about the viability of achieving the targets proposed in the LCFS reauthorization proposal, given the current status of low-CI fuel-producing technologies.

Halfway through the 2010-2020 "compliance" decade, the program is delivering approximately 2% CI reduction (versus an annual target of 1% for 2014 and 2015). ARB maintains the primary reason the program CI reduction targets have not been ratcheted up as originally intended is pending litigation (discussed later in our comments). WSPA is concerned that the program still faces considerable challenges, even as ARB proposes to scale back some of the program's targets, e.g., interim year CI reduction targets, while leaving others such as the 10% 2020 target in place, despite mounting evidence that it cannot be met.

ARB's own estimates indicate the LCFS program as proposed in the reauthorization proposal is not sustainable. Approximately 3% of the 10% CI reduction shown for staff's illustrative scenario for 2020 is derived from accumulated credits (from "over-compliance" during previous years) and only 7% is actual, sustainable CI reductions obtained during the year. While ARB staff forecasts a credit bank build up to 9 MMT at the end of 2015 to help satisfy the otherwise un-sustainable reduction targets, in actuality the credit bank stood at just under 4 MMT at the end of the third quarter of 2014 (since program inception) and, given the rate of credit buildup to date, the assumption that banked credits will reach 9MMT over the next 15 months is aspirational. Even if credit generation sees an increase due to more regulatory certainty, as ARB posits it will, there is unlikely to be enough of a generation increase to meet ARB's projections.

Setting aside the issue of ARB's reliance on an unrealistic initial credit bank at the start of 2016 (to meet the 10% 2020 target), WSPA does not agree that staff's projection of a 7% sustainable reduction in 2020 is accurate. WSPA believes ARB's projections for estimating the degree of market penetration of renewable biogas for motor fuel applications and the volumes of renewable diesel that will be incorporated in the CARB diesel pool are too optimistic. Questionable LCFS credit contributions are also forecasted from the Refinery Investment Credit segment of the re-adoption program. The reasons for WSPA's reservations in these areas are outlined further in the detailed section of our comments.

WSPA notes the "redirection" of ARB's reliance on different sector contributions to achieve the program's CI reduction goals, in particular, the absence of a significant contribution expectation from advanced cellulosic biofuels – an expectation that once provided justification for the original program's ambitious goals. While this appropriately reflects the lack of growth in technologies for advanced cellulosic biofuels, the degree to which such low CI fuels are expected to contribute going forward is now but a fraction of the overall program CI reduction needs. Given ARB's tacit acknowledgment that this area has not grown as initially projected, resulting in a substantial decrease in its potential contribution to program CI reduction, WSPA is surprised that ARB has not reduced program targets accordingly.

Instead, ARB has largely held on to the original program targets (at least for 2020) and looked to fill the CI reduction "gap" created by the lack of development in cellulosic fuels through larger-than-justified increases in reliance on renewable biogas and renewable diesel, and the arbitrary decision to allow the generation of LCFS credits from stationary source segments such the "Refinery Investment Credit" and "Innovative Technologies for Crude Oil Production", and the inclusion of "Pre-LCFS electricity sources (e.g. fixed guideways and electric forklifts)". In WSPA's view, this "redirection" coupled with the overstated focus on credit reliance in the 2016-2020 timeframe without an acknowledgement of the magnitude of sustainable CI reductions, fails to accurately project the true challenges of meeting the program's targets.

WSPA is concerned that if unachievable targets are set at the outset, the regulated community will not receive the benefit of the certainty ARB is seeking to provide with the LCFS because the targets will be viewed as placeholders that will ultimately have to be revised. If overly ambitious targets are promulgated, they may have the unintended consequence of prolonging the climate of uncertainty, sustaining deferred action on compliance plans, investments, etc. that are necessary to the success of the program, and potentially undermining the program's goals. In the case of the readopted LCFS, if the credit bank status for 2015 is confirmed to be substantially lower than staff's expectations (roughly within a year's time from re-adoption), the 2020 CI reduction target will be infeasible and the need for revision will be even more urgent since 2020 will be only four years away at that point.

ARB's ISOR documentation lacks detailed data to clearly support the contention that the program is still feasible. A full analysis of the supply of low CI fuels actually available to California and the projected cost; the supply logistics (marine, rail, etc.) available to accommodate these alternative fuels; the infrastructure needed to blend, transport and dispense these fuels; incentives necessary for consumer acceptance; and other regulatory impediments should all be delineated.

Since the original LCFS adoption package, WSPA has worked with the Boston Consulting Group (BCG) to both analyze ARB's assumptions relating to the LCFS compliance curves but also to provide its own projections of what can sustainably be accomplished by certain timeframes. WSPA and BCG have met several times with ARB during the initial work on the re-authorization in 2014 to compare updated analyses relative to the program's feasibility. WSPA continues to urge ARB to reset the 2020 target CI reduction level to a more realistic and sustainable level of approximately 5%, as indicated in the projections of the Boston Consulting Group's most recent study that has been shared with staff. This WSPA recommendation of the 2020 target factors in staff's proposed lowering of the interim year targets and the associated credit bank impacts it will have.

The attached BCG report (Appendix 1) contains their most recent analysis that compares ARB's and BCG's forecasts and investigates the reasons for the differences. Some of the summary conclusions from the BCG report are:

- A 5.1% reduction in the total fuel pool is sustainable by 2020 based on credits available through blending low-CI fuels (e.g. renewable diesel, biodiesel) and purchasing credits (e.g. electric, natural gas).
- Using the same compliance schedule, BCG forecasts banked credits being exhausted earlier than ARB with annual deficits starting in 2018.
- BCG forecasts a 4.4MMT larger deficit in 2020 versus ARB's scenario
- ARB's near term growth is overestimated [ARB's "illustrative" compliance curves show significantly MORE banked credits in 2014 than are actually going to be available based on projections for the year-end report. While ARB has only published the credit numbers through 3Q2014 as 3.9MMT excess credits, it is highly unlikely this will balloon to 5.5MMT excess credits through 4Q2014.]
- Even ARB's forecast shows only a 6MMT credit bank remaining for 2020, so there is no sustainability anticipated beyond 2020.
- ARB's forecasts of volumes of several low CI fuels through the first three-quarters of 2014 remain excessively aggressive
- The program continues to depend heavily on CI reductions in the diesel/distillate pool.

2. LCFS Program Feasibility – Low CI Fuel Availability

- WSPA requests credible assessment of projections of low CI fuel availability using WSPA criteria, fuel cost competitiveness, plus an assessment of infrastructure and vehicle availability to match with the fuels.

Overall, WSPA's greatest concern continues to be the lack of a credible ARB assessment and forecast of the availability and costs of low carbon fuels and credits that ARB has assumed will be available. We note that multiple caveats are included in ARB's analyses indicating the illustrative scenarios are not forecasts or predictions.

In addition, ARB staff must justify why assumptions that the bulk of the nationwide supply will be delivered to and used in California, are reasonable in light of current and proposed competing programs (i.e., RFS2 and LCFS initiatives in the Pacific Northwest states and B.C.). It is also imperative this analysis include the expected added costs for compliance, including those associated with fuel distribution and refueling infrastructure, and specialized vehicles (e.g., battery electric vehicles).

Although no one can say with any degree of certainty what fuel/credit combinations may be used to attempt to comply with the program, there are a number of assumptions ARB staff has used in the past that are not believable based on EIA projections, historical experience with timing and volumes of new fuel/vehicle introductions, and future market economics.

WSPA has requested several times now that ARB provide an updated analysis based on the technical criteria below, so staff can provide the Board with a realistic update. The technical criteria relate to the three interrelated transportation system components: fuel (availability and cost), infrastructure and vehicles:

Fuel Volumes

The volume analysis should include the following items to assess the capability of the low CI fuel production facilities (current and proposed):

1. Design capacity in gallons per day

2. Date of construction completion

3. Date that feedstock first introduced to process

4. Date that on-specification product first produced

5. Highest utilization demonstrated in a consecutive three month period (utilization is defined as production rate divided by design capacity, inclusive of downtime)

6. Percent of product that was produced on-specification without reprocessing or blending during the period in Question #5.

7. Duration in days of longest continuous period of plant operation

8. Utilization during last calendar year (production rate divided by design capacity, inclusive of downtime)

9. Percent of product that was produced on-specification without reprocessing or blending during the period in Question #8. Qualified biofuels have to be able to replace a certain meaningful percentage of the previous year’s demand for the on- ramp to be triggered.

10. Feedstock availability analysis including what percentage of available feedstock the actual production volume requires. Analysis of feedstock

availability should be done separately for domestic and foreign supply sources.

Footnote: A definition of “success” could, for example, be once answers to questions #5 and #6 exceed 80%. Or, before a facility is deemed to be viable and included in a consideration of low CI fuels facilities to be in ARB’s list of “available fuels” would be the answer to question #5 multiplied by the answer to question #1. Note that typical refinery process utilization ranges between 93 and 98 percent, on an annual basis.

Fuel Cost-competitiveness

Not only is the availability of low CI fuels important, but those fuels must also be cost competitive if the LCFS is to be feasible in a real world market. Accordingly, a cost-competitive analysis must be performed. This analysis should assess how much greater the low CI fuels are in average market costs than petroleum products on a per-gallon basis, and the analysis should also evaluate the role or continued need for subsidies in the cost of the fuels.

Fuel Infrastructure

This analysis should also consider the capability of the distribution system infrastructure (including retail sites) to handle these volumes and types of fuels and what additional infrastructure would be needed, including costs, to support the assessed volumes.

Vehicle Availability

A mandate for further CI reduction should consider whether commercially produced vehicles are available in sufficient quantity to use the low CI fuels. Further, the compatibility of the existing vehicle fleet to use these higher volumes or types of fuels needs to be analyzed. Barriers like consumer acceptance should also be analyzed in an intellectually honest manner with sensitivity runs to bracket an appropriate range of consumer acceptance.

- <u>Low CI Fuel Availability - Three Fuel Examples</u>:

<u>Renewable Diesel</u>

Renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance. However, ARB’s supply projections are optimistic and overly reliant on announced projects and nameplate capacities. Announcements regarding new production facilities are frequently optimistic in their projected startup dates and facilities rarely reach nameplate capacities in the first months or even years following completion of construction as they face startup issues. Feedstock availability is of particular concern for a product like renewable diesel that will be competing with established food and industrial product markets for the same lipid feedstocks.

The critical barriers to the market penetration of renewable diesel, however, are not production levels but blending infrastructure and regulatory hurdles. ARB has projected that renewable diesel will make up 12% of the California diesel pool by 2020, but we anticipate it will reach roughly half that level. Logistical hurdles on pump labeling (FTC regulations), superimposed on the fungible nature of the common carrier pipeline system will be difficult to overcome in the 2016-2020 timeframe. BCG projects that the vast majority of diesel in the state will contain 5% renewable diesel by 2020, with higher percentages seen in select centrally fueled fleet applications, resulting in an overall pool average slightly above 5% renewable diesel.

ARB has speculated that regulated parties may pursue several options for getting around the 5% blending limit imposed by FTC labeling rules.

- <u>Segregated grades of diesel at terminals</u> – Staff contends that selling two blend levels (0-5% and 6-20% renewable diesel) would enable higher blend levels.

  This option is problematic as terminals face multiple logistical constraints when it comes to any attempts at additional product segregation (e.g. plot space for additional tankage). Even where it could be considered, it is highly unlikely to occur until LCFS implementation establishes RD supply stability and justifies the investment in expansion of diesel grade infrastructure.

- <u>Moving entire pipeline/terminal systems to higher blend levels</u> – Some terminal position holders could move to 6-20% blends, causing the retailer community served by those terminals to label accordingly.

  Voluntarily industry adoption of an RD6-RD-20 specification is equally problematic. The existing fungible pipeline system dictates that industry must move in "lockstep" for any geographic move to higher blends. Such a change would have to be implemented through a common carrier pipeline specification change, which can take a lot longer than expected.

- <u>Large-scale fleet blending</u> – Bypassing the traditional supply system to blend high renewable diesel levels for fleet applications.

  This is a very real possibility. Centrally-fueled fleet blending at higher renewable diesel percentages will likely occur but its impact is small and it has already been comprehended in BCG's estimates.

- <u>Relying on an FTC re-interpretation of the underlying law (2007 EISA)</u> – The FTC may revisit their understanding of Congress' intent and remove the regulatory barriers.

  This is the least likely solution. Several unsuccessful inquiries have already taken place by both fuel providers and renewable diesel producers as expanded blending has been pursued for Renewable Fuel Standard and other blending mandate compliance. The FTC has been unmoved on this point. Congress providing the necessary authority (by reopening EISA) is even more unlikely near term.

Furthermore, strong opposition should be expected by the biodiesel lobby to any revision attempt.

In view of the above, terminal blending above 5% (on average) before 2020 is highly unlikely and fleet blending will have only a marginal impact on the overall market balance.

<u>Renewable Biogas</u>

Reliance on large-scale production of renewable natural gas as a supply of LCFS credits is questionable. Investors will weigh high regulatory risk as they consider such projects. Without RFS and LCFS credit subsidies, renewable natural gas for transportation is uneconomic. Cellulosic RINs are estimated to add three times the commodity value of natural gas, the LCFS may add another one to two times the value. While this may seem like a significant motivator for investment, the possibility that these programs may be modified at any time (based on political and/or regulatory reassessment) represents a significant issue for investors as the consider projects whose returns are based solely on the RFS and/or LCFS credit premiums that they generate.

Typical economics (capital investment, absence of need for gas "cleanup", access to gas pipeline, etc.) of biogas utilization drive the application of such gas to power generation and not motor fuel use. We have cautioned ARB that the GHG reduction benefits associated with "re-purposing" biogas from power generation CNG/LNG production are not appropriately accounted for in staff's estimates. ARB's carbon intensity assessment of these products ignores this very real possibility, taking full credit for any renewable CNG/LNG production as though it represents green-field landfill gas production. Should it be found that a significant portion of the landfill gas supply used for CNG/LNG production was redirected from electricity production, much of the compliance value of those biogas products will have been lost.

The current version of CA-GREET2.0 estimates the lifecycle CI of CNG from landfill gas to be 17gCO2e/MJ. If this landfill gas was re-purposed from on-site electricity generation, the amount of electricity displaced from the grid would need to be accounted for as average grid electricity, which has a much higher CI than electricity from landfill gas. CA-GREET2.0 estimates the US-average electricity CI to be 183gCO2e/MJ, while EPA has estimated the CI of electricity from landfill gas to be 11.4gCO2e/MJ. EPA has also estimated that 3.4MJ of landfill gas energy is required to produce 1MJ of electricity*. The increase in the landfill gas CNG/LNG CI from displacing LFG electricity would therefore be:

(1 MJ Elec. / 3.4 MJ LFG) * (183 - 11.4gCO2e/MJ Elec.) = 50gCO2e/MJ LFG

For the example above (Landfill Gas CNG), the CI would increase from 17gCO2e/MJ to 67gCO2e/MJ if re-purposed from on-site electricity generation, or about the same as fossil natural gas.

*Note: *"Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuel Produced from Waste Derived Biofuel," U.S. EPA Office of Transportation and Air Quality Memorandum to Docket EPA-HQ-OAR-2012-0401, July 1, 2014.*

Table 6: CI of Electricity from Landfills that Flared Biogas = 12 kg CO2e/mmBTU (= 11.4 gCO2e/MJ)
Table 5: Efficiency of Electricity Generation from Biogas = 11,700 BTU biogas/kWh (= 3.4 MJ biogas/MJ electricity)

Advanced Biofuels

ARB staff continues to strongly assert that the LCFS program (and more particularly LCFS credit prices) will drive advanced biofuels production. WSPA notes that almost all of the advanced biofuel production facilities ARB and others mention are not in California – challenging the notion that the state is really driving the advanced biofuel market and attracting investments. As previously commented by WSPA in our Wood Mackenzie and BCG contractor work in 2012, the LCFS will draw any limited quantities of these fuels that may be available to California via shuffling resulting in sub-optimal costs and often increased emissions.

When calculating/projecting future biofuels supply, ARB should not rely on press announcements as credible evidence of actual facilities/volumes, since many projects are cancelled after initial press announcements but prior to construction, based on engineering studies that are completed and a more definitive cost estimate becoming available. ARB should count facilities that have started construction for potential facility/volume availability in the next 2 – 3 years. If construction has not started, then a discount factor of at least 50% should be used in projecting future capacity. When using past growth rates and projecting them into the future, ARB should take into account the period of two or so years of essentially no growth.

3. Assessment of LCFS Program – Major Milestone Review

Although ARB has conducted two formal Periodic Reviews of the LCFS program since its inception, WSPA believes ARB needs to conduct a Major Milestone review to inform transportation fuel consumers and state policymakers of the program's progress towards meeting its objectives over the first 5 years of its existence. We note that during the 2014 Advisory Panel meetings there was discussion of the need for a thorough review which provided more definitive data. We urge ARB to conduct such a review where the analysis is focused on quantifiable metrics that should include, at a minimum, the following considerations that are different in scope from the normal Periodic Reviews:

• Actual GHG reductions achieved through the program (in-state and out-of-state reductions quantified separately), and the avenues/means used to drive those reductions.

• GHG reduction achieved solely by the LCFS, exclusive of other programs, (such as the federal RFS2 and CAFÉ standards, or the California ZEV mandate.) To objectively assess LCFS program progress, GHG reduction benefits should be viewed on an incremental basis, i.e. above and beyond what is delivered from these other programs.

• Costs associated with the LCFS program. These should include any subsidies or program expenditures (i.e., total cost for the California taxpayer), and any additional fuel costs.

• Cost-effectiveness of the LCFS program. The analyses should compare the cost-effectiveness of the incremental GHG reduction delivered by the LCFS program (in terms of dollars per ton CO2 reduction) to those of other GHG reduction programs such as the California Cap and Trade Program or and vehicular efficiency programs (CAFÉ).

• Prospects for future successes in terms of GHG reduction which may be attributed to the LCFS program [in the absence of other related regulatory policies], and a reasonable assessment as to their probability of success.

• Assessment of incremental incentives for innovation and in-state employment paid for by state or local dollars. We believe the California public should be apprised as to what their taxes have supported, their incremental fuel and vehicle costs, and be allowed to judge the effectiveness of the LCFS program versus other transportation-related GHG reduction approaches in a transparent, objective manner.

Economic Impact Analysis Update

To add to the above note on a Major Milestone review, there appears to be a false sense of the degree of updates staff has provided – especially for the economic analysis. There has been minimal effort to update the 2009 economic impact analysis, and during the various 2014 Workshops staff indicated there would not be a comprehensive update to the five year old economic impact analysis.

During the 2011 program updates ARB stated that much of the 2009 analysis remains valid, but acknowledged the need for an entirely new analysis. It was also stated that staff was considering using a contractor to conduct a more comprehensive economic analysis of the LCFS. We were told such an analysis would not be completed until sometime in 2012 or early 2013, but this seems to not have materialized.

4. Cost Containment Mechanism – Credit Clearance

WSPA is concerned that the cost containment mechanism proposed will also act as either a price floor or have the unintended effect of raising LCFS credit prices. Because LCFS credits do not expire, the proposed cost containment mechanism will provide an incentive for those parties that have excess credits to hold on to their credits if they believe that a Clearance Market will occur in the future or to hold out for an offer that is near the Clearance Market price. This negative impact of the cost containment mechanism could be partially mitigated if participation in the Clearance Market was voluntary and if staff re-inserts the deficit carry over provision that was in the previous LCFS reglulations (which WSPA is also suggesting).

In June 2014 WSPA commissioned a paper by Analysis Group, Inc. to review the cost containment mechanisms being proposed by ARB at that point in time.

The Analysis Group pointed out that there "*is a meaningful risk that LCFS compliance costs will increase significantly at some point in the near- to medium-term due to the* *confluence of an increasingly stringent standard, and diminishing opportunities for low-CI fuel substitutions. By virtue of the rate at which the LCFS standard declines, the nature of the transportation systems regulated, and the LCFS design, there is a meaningful risk in the near- to medium-term that compliance with the LCFS could become increasingly difficult. Due to these factors, the cost of actions to generate LCFS credits could rise significantly. Despite the current large bank of surplus credits, the risk of either cumulative deficits or significantly elevated credit costs is high, although the timing and severity of these outcomes is uncertain*."

ARB recognized the need for some mechanism to accommodate short-term market disruptions and prevent excessive LCFS cost of compliance during such periods from ultimately impacting fuel prices. WSPA's advice in that regard has been that the setting of realistic goals coupled with frequent program reviews to ensure ample credit availability in a liquid LCFS credit market would obviate the need for a cost containment mechanism such as the Credit Clearance Market that ARB is proposing as part of the re-adoption package.

WSPA agrees with the Analysis Group's finding that, "*While regulated parties are building up a cumulative credit surplus in the early program years, there is a definite risk that these credit surpluses will become exhausted as the standard becomes more stringent, which could lead to very high costs and/or a cumulative credit deficit, which would increase the risk that regulated parties could not achieve compliance. Current ARB proposals that might add limited credits to the market (e.g., Innovative Technologies for Crude Oil Production) would only shift out the date at which these barriers are hit. While there is much technological uncertainty about the timing and severity of these constraints, there is a clear risk that compliance with the LCFS could become increasingly costly and challenging to comply with. Thus, there is justified concern about cost containment*."

ARB staff maintains that sufficient low CI fuels and credits will be available and, thus, the cost containment mechanism will be seldom (if ever) needed. Staff's vision is that, when it is necessary, it will be in response to some short-lived market "blip" or disturbance that will quickly give way to reestablishment of equilibrium. Staff acknowledges that this tool is not designed to accommodate systemic and prolonged LCFS credit shortages. Staff considers the ability to carry deficits forward (albeit with interest) for up to five years an "insurance policy" and sees no particular negative aspects to the end-of-year credit clearance auction they are proposing (where regulated parties can buy their pro-rata share of pledged credits at a price as high as $200/ton).

WSPA is opposed to the inclusion of such a cost containment mechanism in the LCFS because we believe that it will not accomplish its stated objective (contain costs) and will instead have a number of undesirable (and unintended) consequences. More specifically, the Credit Clearance Market (CCM):

<u>Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist</u>.
Obligated parties that participate in the year-end auction of credits pledged by suppliers at costs as high as the pre-determined "cap" Maximum Price, have no recourse but to

carry over any remaining deficit into the following year with interest. There is no way to retire deficits if shortages persist year to year. Instead, obligated parties face the prospect of an ever-increasing accrued financial liability that is essentially outside their control. In a market that is consistently short credits year after year, the ability to defer unsatisfied obligation (with interest) offers little comfort to the regulated community staring down the specter of ever-increasing deficits and no method to retire part of the obligation generated by an infeasible standard.

<u>May drive credit costs up (if credits are withheld from the regular market to get a higher CCM cost)</u>.

During periods of rising costs (i.e., credit shortages in the open market), the CCM will not keep credit costs in check. In fact, the CCM to clear the market at the end of the year is meaningless during a credit-short environment as there will not be any remaining credits to be brought to the table by sellers. The compounding of “interest” on the carryover/deferred balances will ensure credit buyers soak up the available pool of real LCFS credits in the market during the year rather than wait for the CCM. The pool of real LCFS credits available is fixed – it is only their cost that remains in question. Staff’s setting of the Maximum Price at $200/ton will serve as the benchmark for credit costs in that environment.

During periods of stable or declining costs (i.e., credit surplus in the open market), the CCM cap Maximum Price creates an artificial “floor” value below which sellers will be hesitant to offer real LCFS credits for sale to the regulated community at substantially lower costs. This would artificially increase compliance costs – as credit costs will be artificially raised to (or near) the ARB cap and very few transactions will take place before the end-of-year sale. Credit trading would be seriously impaired as the open market would not be allowed to function as it should.

<u>Provides no liability protection against invalid credits secured through the CCM.</u>

We reference the issue of lack of an acceptable liability defense provision or protocol in the LCFS to protect obligated parties from potentially fraudulent credit sellers elsewhere in our comments. For the purposes of discussing this topic within the CCM provisions, we emphasize that the only protection we have as buyers of credits is to perform our due diligence and carefully screen the parties we choose to engage as partners in LCFS credit-buying transactions. It appears to WSPA that we will not be afforded this ability with respect to the credits we are obligated to purchase (our pro-rata share) through the CCM. Moreover, the timetable set by ARB to organize and complete the CCM raises concerns that the agency will be undertaking minimal, if any, screening of the credits that are pledged by sellers for the CCM. WSPA objects to the fact that regulated entities may potentially wind up in a position of non-compliance through no fault of their own simply because there is a credit shortage and they are required to participate in a CCM that provides them no control over what credits they buy and from whom.

Offers no connection between CCM outcome, program off-ramps, future CI reduction targets

It stands to reason that LCFS credit market liquidity (measurable potentially through a number of different indicators) is not only essential to the program's success but, also, that the absence of such liquidity should be viewed as a clear signal that the program's CI reduction targets are overly ambitious and that the regulated community is finding it difficult to meet its obligations and remain in compliance. There is no connection or tie-in in the current CCM proposal to initiate a comprehensive program review should the alarming trend of potential credit shortages materialize and become evident through the CCM.

Is incomplete in its definition of the mechanics (recordkeeping, reporting, etc.) of deficit carryover

Even if all of the above issues were resolved, the CCM proposal in the ISOR and draft regulatory language is sorely lacking in the execution/implementation details that would allow the regulated community to understand exactly how it would work. For example: What is the "order" of applying generated credits (through blending or purchases) to the various potential uses for a regulated party o on any given year (e.g., meet the current year's obligation, retire previous years' obligations)?

Finally, the proposal to make public the long and short credit positions of regulated parties flies in the face of the principle of confidential business information. A regulated party's competitive position could be seriously compromised by the publication of this information. In addition, this information would give competitors both an understanding of a regulated party's compliance strategy and a view into the regulated party's fuel and credit acquisition activity for the year. Using this information and average market pricing, one could estimate the financial impact of LCFS compliance on a regulated party.

Alternative to the CCM

In lieu of the CCM, a dual approach of setting reasonable, practically achievable CI reduction targets and holding frequent (annual) program reviews to ensure that the program remains on track and the LCFS credit market is healthy should prevent the type of cost excursions that CCM is meant to accommodate. More specifically, staff could eliminate the proposed CCM and:

- Provide for annual mandatory program reviews with the first one due by 1/1/2017. The initial review should include LCFS credit history including actual credit generation, obligation, and a comparison of actual current credit bank versus staff's projections in the ISOR. As part of the review, staff should include a projection of where the credit bank is expected to be in the future. If overall credit generation is above or below staff's projections (plus/minus a modest estimate allowance/tolerance), CI reduction targets should be adjusted up or down to re-establish an aggressive yet achievable program.

- Establish triggers that would require early program reviews prior to the planned annual staff report. Specific, measurable thresholds and triggers should be established as part of this process. Some examples of such triggers for an early review of subsequent year CI targets include:

  - Monthly credit cost exceeds $150
  - Industry credit bank falls below 5 million metric tons (MMT)
  - CA fuel price > "x"cpg above national average

- Incorporate a simple carryover rule for one-off company imbalances. The provisions of this segment could be tailored along the lines established for RINs by EPA in the RFS program, with potential additional enhancements. Key features could include:
  - A regulated party may carry over a deficit balance for one year, without penalty
  - Credits must be retired in the following year to completely settle the deficit balance
  - A deficit balance cannot be carried over two years in a row

This simple-to-execute approach would satisfy staff's stated goal of addressing short-term tightness in the credit market, while avoiding the market-manipulating aspects of the proposed CCM. Neither this solution nor the CCM can address the very real possibility of a long-term credit shortage. This must be met with the program reviews and schedule adjustments recommended above.

If staff insists on moving forward with a CCM, WSPA recommends that, at a minimum, the following changes should be made:

- Participation in the CCM should be voluntary. In order for ARB to determine whether or not to hold a CCM for a particular year, ARB could issue a "Call For Deficits" similar to the "Call For Credits" already incorporated in staff's proposal.

- Regulated parties that have pledged credits to sell into the Clearance Market, and have not sold or contractually agreed to sell all their pledged credits, cannot reject an offer to purchase pledged credits at the Maximum Price.

- The LCFS credit balance and the individual entity names should be treated as highly confidential because the release of this information could adversely impact business operations. The release of the LCFS credit balance would provide competitors and other LCFS credit market participants with short or long position knowledge.

- The Deficit Carryover provisions should be reinstated. WSPA objects to the removal of the Deficit Carryover provisions in the proposed regulations and request that the current provisions be retained as there may be planning or operational reasons why a regulated party may wish to carry deficits from one year to the next.

On many occasions, WSPA has raised concerns about the interactions between the LCFS and the GHG cap-and-trade program.[1] In general, "quantity-based" programs such as the

LCFS (which relies on averaging across entities to meet a standard) that overlap with a cap-and-trade program do not generate additional emission reductions but do potentially raise costs. Because the LCFS affects sources both under and outside of the GHG cap-and-trade system, these interactions are somewhat more complex. However, this does not affect the conclusion that these interactions create significant concerns for the environmental and economic efficacy of the LCFS.

ARB's cost containment proposal in no way affects these conclusions. The cost containment proposals may mitigate the extent to which the LCFS raises the costs of meeting the AB 32 targets compared to a policy that relies solely on the GHG cap-and-trade program, but does not affect the conclusion that the LCFS raises overall costs.

WSPA provides additional detailed comments later in this document regarding specific concerns about the cost containment provision as proposed by ARB.

[1.] *see* Schatzki, Todd and Robert Stavins, "Implications of Interactions for California's Climate Policy," Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

Legal Comments:

1. ***ARB has failed to comply with statutory requirements with respect to enacting a fuel specification, including inadequately analyzing fuels impacts through multimedia analysis.***

WSPA strongly disagrees with ARB's characterization of the LCFS as a fuel "standard" rather than a fuel "specification." ARB argues that because the LCFS governs the production process for fuels, rather than imposing "an ARB mandate on a vehicular fuel's particular composition," the LCFS is not a fuel "specification" subject to the Health & Safety Code's requirements for fuel control measures. Initial Statement of Reasons for Proposed Rulemaking, Proposed Re-Adoption of the Low Carbon Fuel Standard ("ISOR"), at III-58 – III-63. ARB argues that a fuel "specification" would be more like a recipe, with quantifiable measurements of components that would make up the fuel; because carbon intensity measurements rely more on how a fuel is made than what is in it, ARB says the LCFS is not a "specification." *See* ISOR at III-61.

But contrary to ARB's assertion, carbon intensity is a criterion or "specification" to which motor vehicle fuels must comply. The Health & Safety Code nowhere requires that a "specification" relate only to the quantity of fuel components. Indeed, the Code recognizes a fuel specification for light-duty vehicle exhaust emission standards—standards that, like the LCFS, are based on overall emissions from fuels as opposed to quantification of their particular components. Cal. Health & Safety Code § 43018(d)(1).

Furthermore, the LCFS will change specifications of California reformulated gasoline and diesel and may require fuel additives to be added to or removed from fuels and new fuels to be used statewide. ARB Draft LCFS Regulation, § 95422

("[T]he transportation gasoline and diesel fuel for which a regulated party is responsible in each calendar year must meet the average carbon intensity standards set forth in this section . . . "). ARB is not permitted to avoid the statutory requirements associated with fuel control measures by simply labeling the LCFS a "standard" as opposed to a "specification."

Furthermore, the Ninth Circuit has already considered the LCFS to be a fuel control measure. *See Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070 (9th Cir. 2013) (recognizing that the LCFS is "a control respecting a fuel or fuel additive and was enacted for the purpose of emissions control"). In fact, ARB itself has argued that it should have the authority to enact the LCFS precisely because the LCFS is a control on motor vehicle fuels. *See* Defendants' Memorandum in Support of Cross-Motion for Summary Judgment, *Rocky Mountain Farmers Union v. Goldstene*, Case No. 09-CV-02234 (C.D. Cal. Dec. 17, 2010) at 2, 11-18. In its *Rocky Mountain Farmers Union* papers, ARB admitted that "[t]he LCFS controls the carbon intensity of fuels offered for sale in California. It does so by applying a lifecycle analysis." *Id*. at 15. ARB even pointed out that as fuel sources diversify, "differentiating among them on the basis of lifecycle carbon intensity becomes even more critical"— in other words, carbon intensity <u>is</u> a specification of fuels that is controlled by the LCFS with the goal of reducing emissions.

ARB cannot now change its tune in an effort to escape the statutory requirements applicable to fuel control measures. Under the California Health & Safety Code, ARB must assess not only the cost-effectiveness of such controls, but also the technological feasibility of the controls, including, but not limited to, the availability, effectiveness, reliability, and safety of the proposed technology. Cal. Health & Safety Code § 43013(e). ARB's documentation does not adequately assess any of these factors. In addition, as discussed in greater detail below, ARB has failed to undertake the requisite multimedia analysis for the LCFS, also mandated by the Health & Safety Code.

<u>*Multimedia Analysis Under Health & Safety Code § 43830.8*</u>

One key requirement ARB has attempted to avoid by its improper characterization of the LCFS, is conducting multimedia analyses for fuels that will likely be used to comply with the LCFS, as required under the Health & Safety Code.

Under section 43830.8 of the Health & Safety Code, ARB may not adopt "any regulation that establishes a specification for motor vehicle fuel" unless the regulation, and a multimedia evaluation for the regulation, are reviewed by the California Environmental Policy Council ("Council"). Cal. Health & Safety Code § 43830.8(a). A multimedia evaluation requires ARB to identify and evaluate "any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications." Cal. Health & Safety Code § 43830.8(b).

ARB staff promises they will perform a multimedia analysis later—either if and/or when ARB adopts a new fuel specification (such as the current specification for biodiesel) or if and/or when it amends an existing fuel specification (such as natural gas or E85). ISOR at III-64. Such an approach fails to address upfront any adverse environmental impacts that may be associated with producing fuels that can meet the carbon intensity requirements of the LCFS. Multimedia evaluations are necessary in order to obtain a full and independent assessment of the range of potential environmental impacts of any newly proposed fuel regulations across all media. This assessment should be completed as soon as feasible, not at later dates if and/or when ARB chooses to prepare it.

In addition, delaying such an evaluation until a later time could hinder the development of the full range of LCFS-compliant fuels due to concerns about allocating any significant resources to the commercialization of a fuel that could ultimately fail a multimedia evaluation.

Nearly six years have passed since ARB stated, during the first LCFS rulemaking, that there was not enough information to conduct a multimedia evaluation for fuels designed to comply with the LCFS. ARB and fuel producers have much better information now regarding the types and blends of fuels that will likely be used under the LCFS. In fact, ARB completed a multimedia analysis for biodiesel in conjunction with the Alternative Diesel Fuel (ADF) rulemaking. ARB should now complete multimedia analyses for all fuels that will likely be used to comply with the LCFS in order to comply with its statutory duty under the Health & Safety Code.

2. ***Combining the ADF and LCFS processes into one CEQA "project" is not procedurally appropriate, and results in an insufficient environmental analysis.***

ARB should analyze the LCFS and the ADF as two separate projects. At the very least, ARB must acknowledge the possibility that the two regulations will not pass concurrently, and should rework the Draft EA to clarify the impacts from each of the regulations, and the specific mitigation measures applicable to each.

The Draft EA published by ARB is the environmental document for both the LCFS and the ADF regulations. While these two rulemakings are being run concurrently, parallel to one another, they are also being run as two separate processes. Because the two regulations are subject to two separate rulemakings, there is the possibility that one regulation could pass but the other could not, or that one regulation could be challenged and its implementation delayed while the other continues to move forward.

ARB has cited CEQA Guidelines § 15378(a) in support of its approach to combine environmental review of the two regulations into one CEQA "project." However, section 15378(a) of the Guidelines simply states that a "project" is "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment…" While section 15378(c) of the Guidelines clarifies that a "project" can include an activity that requires more than one discretionary approval by one or multiple government agencies, the Guidelines nowhere provide for a "project" that encompasses two separate activities that happen to be related to one another, but are not interdependent. *See* CEQA Guidelines § 15378(c).

Interdependence, an element lacking here, is key to including separate actions under the umbrella of one CEQA "project" for purposes of environmental review. *Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1230-1231 [finding a road realignment and construction of a shopping center were part of the same "project" because the shopping center's opening was legally dependent upon the road's realignment]. The LCFS and ADF regulations certainly pertain to related subject matter, but they are not legally dependent upon one another—the LCFS can (and has, in the past) exist without the ADF, and vice versa.

Both statute and regulation recognize the need to analyze separate "projects" in circumstances similar to these. For example, while a real estate developer may request a rezoning of property, as well as a tentative subdivision map, for purposes of effectuating development, those two related but separate actions are recognized as distinct "projects." *See El Dorado Union High School Dist. v. City of Placerville* (1983) 144 Cal.App.3d 123, 129-130; CEQA Guidelines § 15037. Just as with the two related but distinct rulemakings here, each of these two legal actions, which may very well impact the same development, nonetheless may occur without the other and in completely separate processes, and may produce significantly different impacts.

Simply put, CEQA does not allow ARB to take two different activities which each have different impacts and require different analyses and pass them off as one "project" to streamline its environmental review process. The process that ARB has adopted here makes it impossible to separate out which impacts stem from the LCFS regulations and which from the ADF regulations, <u>even though the two rules are being considered in separate rulemakings, have distinct impacts as a practical matter, and may not both be adopted, or may be adopted on different schedules</u>.

CEQA requires that environmental review documents be "written in a manner that will be meaningful and useful to decision-makers and to the public." Cal. Pub. Res. Code § 21003(b); *see Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 392. When neither decision-makers nor the public can meaningfully understand the impacts that will arise from each proposal and available mitigation, the usefulness of the Draft EA as a valuable decision-making tool for is significantly undermined, contravening the intent of CEQA.

3. ***The Draft EA does not sufficiently analyze alternatives.***

Under CEQA, an environmental review document "must consider a reasonable range of alternatives to the project" and must "make an in-depth discussion of those alternatives identified as at least potentially feasible." *See Preservation Action Council v. City of San Jose* (2006) 141 Cal.App.4th 1336, 1350; *Sierra Club v. County of Napa* (2004) 121 Cal.App.4th 1490. The purpose of such an analysis is to allow informed decision-making, and the onus for analyzing a sufficient range of alternatives falls squarely on the agency. *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 405.

But ARB's Draft EA falls far short of this requirement. The Draft EA only analyzes a "no project" alternative—LCFS regulations being set aside as a result of the *POET* decision and no adoption of the ADF; a second alternative—re-adopting the existing LCFS without any of the proposed updates and adopting the ADF regulation as proposed; and finally, a "Gasoline-Only Compliance Curve" alternative—an alternative that would remove the diesel standard from the LCFS so that the compliance curves apply only to gasoline and gasoline substitute fuels. Despite the Draft EA's statement that it presents a fourth action alternative—the "No Trading Case Alternative" –ARB never includes a description of that alternative in the Draft EA. Draft EA at 130.

Additionally, ARB's description of the alternatives is somewhat misleading. The alternatives that ARB discusses are more accurately described as: (1) no LCFS and no ADF; (2) re-adoption of the existing LCFS and adoption of the proposed ADF as-is; and (3) the "Gasoline-Only Compliance Curve Alternative," which, like the first alternative, would not adopt the proposed ADF, or any rule on diesel fuels. There is no analysis of an alternative that would involve re-adoption of the proposed LCFS with a different ADF regulation, or of a different approach to the LCFS beyond simply dropping diesel fuels from the regulation. In contravention of CEQA, this analysis overlooks potentially less impactful options. *See Citizens of Goleta Valley v. Board of Supervisors* (1990) 53 Cal.3d 553, 566.

The mere three alternatives presented by the Draft EA insufficiently represent the broad scope of alternatives, and fail to take into account clearly feasible scenarios—such as an ADF regulation that is substantively different from the one proposed by ARB. In fact, the Draft EA analyzes no alternatives beyond a "no project" alternative for ADF: either the ADF is not adopted at all, or it is adopted exactly as is. ARB cannot limit the alternatives analysis on the ADF without explaining "in meaningful detail" the basis for its conclusion that there are no feasible alternatives to the ADF as proposed. *Laurel Heights Improvement Assn.*, 47 Cal.3d at 405.

CEQA requires that the Draft EA explore more alternatives than the three presented here. ARB has provided an insufficient alternatives analysis in connection with these rulemakings, and therefore the Draft EA should be revised accordingly.

4. ***The Draft EA does not sufficiently analyze air quality impacts.***

CEQA requires that reasonably foreseeable impacts of a project must be adequately analyzed and, if necessary, mitigated by the agency. Cal. Pub. Res. Code § 21003(b); *see Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 392; *Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 431 . But ARB has not adequately analyzed the potential impacts of the interplay between NOx and VOC emissions stemming from the implementation of the LCFS and ADF.

The Draft EA does not attempt to assess the impacts of the LCFS and ADF regulations on ambient ozone and PM <u>concentrations</u>. Instead, ARB staff simply analyzed the impacts of the LCFS in combination with the ADF on the <u>emissions inventory</u>. Table 4-1 of the Draft EA summarizes ARB staff estimates of the NOx emissions impacts of the LCFS and ADF regulations. That table reports a net reduction in NOx emissions of 1.0 tons per day in 2020, growing to 1.3 tons per day in 2023. The Draft EA then <u>asserts</u> that the "long-term impacts on air quality would be **beneficial**." (emphasis in original text)

Ozone formation chemistry is highly non-linear and so to assess whether the proposed NOx reduction would bring about discernible reductions in ambient ozone, photochemical modeling is necessary. Because the draft EA does not include the impact of LCFS and ADF on VOC emissions, it is impossible to even qualify the net ozone response due to the regulation.

Air quality impacts of the LCFS are addressed in a recent report prepared by ENVIRON International Corporation for the Coordinating Research Council.[1] Among the findings of that report were:

- The LCFS rule constitutes a potential regional control strategy that has not been specifically studied.
- Reductions in precursor emissions (i.e., NOx, VOC reductions) do not always provide air quality benefits, because ozone chemistry is highly non-linear.

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[1] "Low Carbon Fuel Standard Program Air Emissions Effects," Prepared by ENVIRON International Corporation, CRC Project No. A-86, September 24, 2014. http://www.crcao.com/reports/recentstudies2014/A-86%20Low%20Carbon%20Fuel%20Standard%20Program%20Air%20Emissions%20Effects/CRC%20A86%20Final%20Report_%20Sep30_2014.pdf

- In the 2009 rulemaking ARB asserted that due to the relatively small magnitude of emission reductions associated with LCFS it was not practical to expect the air quality model to reasonably predict the cumulative potential benefit on ozone air quality. However, such modeling may be warranted.

5. ***Formulas have changed without the appropriate level of transparency.***

Key elements of the regulation depend on data that are used in calculations that compute indirect land use change and carbon intensity values relevant to the regulation's overall compliance scheme. Changes in the type of data used to compute these values can therefore have a significant effect on the thresholds regulated entities need to meet to come into compliance.

ARB has removed indirect land use change values from the look-up tables that were included in the prior version of the regulation, and now simply describes a credit calculation which requires the incorporation of a land use modifier. The values for such a modifier are not included in the regulation.

Additionally, the carbon intensity calculation process relies on CA-GREET. However, ARB has failed to provide a transparent process to outline bases for changes to the GREET model or allow input for future changes to the model is lacking. ARB acknowledges GREET is used "to provide many emission factors, life cycle inventory data, and fuel cycle emissions values." ARB, LCFS Reauthorization Initial Statement of Reasons, p. II-20. In fact, ARB admits that changes to the GREET model were the impetus for OPGEE revisions—but the GREET changes themselves lacked transparency; even ARB's comparison of the updated model to prior models offers conclusory statements of changes rather than explanations for them. *See, e.g.,* ARB, Comparison of CA-GREET 1.8B, GREET1 2013, and CA-GREET 2.0, pp. C-2-C-3, C-8-C-9. Nothing in the regulations suggests future changes to GREET will be more transparent.

Similarly, the sources for data to be used in calculating the Annual Crude Average carbon intensity value have changed, and that data is now to be provided by two different state agencies, with no apparent opportunity for verification or explanation of the data's bases.

Each of these actions opens the door to changes to key formulas outside of the rulemaking process and without opportunity for public comment. When regulations are amended, the California Administrative Procedure Act requires "basic minimum procedural requirements" for rulemaking, including giving interested parties an opportunity to comment on the rulemaking, and a response to public comments. *See Tidewater Marine Western, Inc. v. Bradshaw* (1996) 14 Cal.4th 557, 558; Cal. Gov. Code § 11346. But the proposed regulations attempt to avoid public discourse on potentially significant changes to the implementation of the LCFS by tying key values that are the rule's backbone to calculations and data that could change at any time, with no explanation—essentially a *de facto* amendment of the regulation with no public process.

ARB must explain the bases for relying on the data sources it has chosen, and must provide more certainty that key values and calculations will not change without public input.

6. ***ARB does not have the authority to compel regulated parties to purchase credits without the capability of verifying those credits.***

The regulations penalize credit holders if they hold invalid credits, even if that is through no fault of their own. Because credits must be verifiable, ARB lacks power to require entities to participate in the credit scheme without providing some level of certainty that credits validly represent the reductions they purport to represent. *See* Cal. Health & Safety Code § 38562(d)(1) ["Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, ***verifiable***, and enforceable by the state board …"] [emphasis added].

The statute and regulations do not address independent verification by purchasers of credits, and we have not located any comparable program with such provisions. However, even if buyers were provided the opportunity to verify credits prior to purchase, ARB's authority to suspend, revoke or modify credits under proposed section 95495 would not be limited and, as a result, there is still a risk credits could be invalidated by ARB.

Such a scenario is not without precedent. In 2012, EPA invalidated over 60 million Renewable Identification Numbers (RINs), the tradable credits that are generated as part of the federal Renewable Fuels Standard program, due to criminal fraud perpetrated by certain RIN generators. Because the RFS was set up as a strict buyer liability system, unknowing, good faith obligated parties were left with worthless invalidated RINs and faced enforcement penalties from EPA. ARB should avoid the risk of creating a similar situation under the LCFS regulations.

However, the risk of invalidation could be reduced by limiting the bases for invalidation under proposed section 95495(b)(1) and adding a statute of limitations on ARB's right to commence invalidation procedures.

WSPA therefore requests the following changes be made to the regulations (bold, underlined type):

Section 95495(a)

<u>(1)</u> If the Executive Officer determines that any basis for invalidation set forth in subsection (b)(1) below occurred, in addition to taking any enforcement action, he or she may: suspend, restrict, modify, or revoke an LRT-CBTS account; modify or delete an Approved CI; restrict, suspend, or invalidate credits; or recalculate the deficits in a regulated party's LRT-CBTS account. For purposes of this section, "Approved CI" includes any determination relating to carbon intensity made pursuant to section 95488, or relating to a credit-generating activity approved under section 95489.

<u>(2) The Executive Officer shall commence enforcement actions under subsections (b)(1)(A)-(F) as follows:</u>

<u>(A) The Executive Officer shall commence an action under subsections (b)(1)(A), (C), or (D) within one (1) year from either the date that the subject Approved CI or credit was generated in accordance with section 95486 or the date upon which disputed data was reported in accordance with section 95488, as applicable.</u>

<u>(B) The Executive Officer shall commence an action under subsection (b)(1)(B) arising from incorrect material information submitted in connection with an Approved CI or credit transaction within one (1) year from either the date of approval of the CI or the recordation date, as defined by section 95487, of the first transaction wherein incorrect material information was submitted, as applicable.</u>

<u>(C) The Executive Officer shall commence an action arising from a transaction made in violation of applicable laws, statutes and regulations under subsection (b)(1)(E) within one (1) year from the recordation date, as defined by section 95487, of the disputed transaction or from the date the credit was generated in accordance with section 95486, as applicable.</u>

<u>(D) The Executive Officer shall commence an action under subsection (b)(1)(F) within six (6) months from the date that a party refused to provide records or failed to produce records within the required time.</u>

Section 95495(b)(1)

Determination that a Credit, Deficit Calculation, or Approved CI is Invalid.
(1) *Basis for Invalidating.* The Executive Officer may modify or delete an Approved CI and invalidate credits or recalculate deficits based on any of the following:
(A) any of the information used to generate or support the Approved CI was incorrect **for reasons including <u>due to</u>** the omission of material information **or changes to the process following submission**;
(B) any material information submitted in connection with any Approved CI or credit transaction was incorrect;

(C) fuel reported under a given pathway was produced or transported in a manner that varies in any way from the methods set forth in any corresponding pathway application documents submitted pursuant to section 95488 (or former section 95486, effective January 1, 2010);
(D) fuel transaction or other data reported into LRT-CBTS and used in calculating credits and deficits was incorrect or omitted material information;
(E) credits or deficits were generated or transferred in violation of any provision of this subarticle or in violation of other laws, statutes or regulations **directly applicable to the credit generation or transfer**; and
(F) a party obligated to provide records under this subarticle refused to provide such records or failed to produce them within the required time.
For purposes of this subsection, "material" means information directly relevant to the generation and calculation of credits under section 95486 or the requirements for credit transactions under section 95487, as applicable.

7. ***Enforcement provisions with respect to credits and carbon intensities are deficient.***

If invalidation of a credit or CI creates a deficit, the generator and/or holder of the credit will have 60 days to correct the compliance issue by purchasing new credits. *See* proposed section 95495(b)(4) ("If [the Executive Officer's] final determination invalidates credits or deficit calculations, the corresponding credits and deficits will be added to or subtracted from the appropriate LRT-CBTS accounts. Where such action creates a deficit in a past compliance period, the deficit holder has 60 days from the date of the final determination to purchase sufficient credits to eliminate the entire deficit. A return to compliance does not preclude further enforcement actions.").

The proposed regulations do not include an appeals mechanism for challenging the Executive Officer's final determination as to invalidated credits. Although appeals may be brought in Superior Court pursuant to Civil Procedure Code section 1085, it would be preferable for ARB to create a hearing and appeals procedure within its regulations. The 60-day period for correcting deficits should not commence until appeals are exhausted.

WSPA therefore requests the following additions to the regulations (bold, underlined type):

Section 95495(b)(2)

Notice ***and Opportunity for Hearing***. Upon making an initial determination that a credit, deficit calculation, or Approved CI may be subject to modification, deletion, recalculation, or invalidation under subsection (b)(1), above, the Executive Officer will notify all potentially affected parties, including those who hold or generate credits or deficits based on an Approved CI that may be invalid, and may notify any linked program. The notice shall state the reason for the initial determination **<u>and the party's right to request a hearing</u>**, and may be distributed using the LRT-CBTS. Any party receiving such notice may submit, within 20 days, any information that it wants to the Executive Officer to consider **<u>and, if desired, its request for a hearing.</u>** The Executive Officer may request information or documentation from any party likely to have information or records relevant to the validity of a credit, deficit calculation, or Approved CI. Within 20 days of any such request, a regulated party shall make records and personnel available to assist the Executive Officer in determining the validity of the credit, deficit calculation, or Approved CI. **<u>If a party requests a hearing on the Executive Officer's initial determination, the Executive Officer must set a hearing date no later than 60 days from the date of the hearing request.</u>**

Section 95495(b)(4)

Final Determination.

<u>(A)</u> Within 50 days after making an initial determination under sections 95483.3(b)(1) and (2), above, **<u>or holding a hearing, whichever is later,</u>** the Executive Officer shall make a final determination based on available information whether, in his or her judgment, any of the bases listed in subsection (b)(1) exists, and notify affected parties and any linked program. **<u>Affected parties may appeal the Executive Officer's final determination to the Board within 30 days of receiving notice of the Executive Officer's final determination. Such appeals shall be placed on the agenda of the next regularly scheduled Board meeting.</u>**

<u>(B)</u> If the final determination invalidates credits or deficit calculations, the corresponding credits and deficits will be added to or subtracted from the appropriate LRT-CBTS accounts. Where such action creates a deficit in a past compliance period, the deficit holder has 60 days from the date of the final determination **<u>or the disposition of any appeal, whichever is later,</u>** to purchase sufficient credits to eliminate the entire deficit. A return to compliance does not preclude further enforcement actions.

8. ***ARB's proposed per-day penalties for violations of the LCFS are unnecessary.***

Proposed section 95494 sets penalties for the failure to demonstrate compliance at the end of a compliance period or carry over all deficits; under the proposed regulations, such a failure would constitute a separate violation for each day of the compliance period or, alternatively, ARB could impose a penalty of $1000 per deficit.

WSPA opposes a per day penalty, and proposes that ARB's suggested alternative penalty of $1000 per deficit be employed. While AB 32's enforcement provisions provide for per day penalties when a violation results in the emission of an air contaminant, where, as here, no actual emission of air contaminant is occurring on a per day basis, the imposition of such a penalty would be unnecessary. *See* Cal. Health & Safety Code §§ 42400.1, 42400.3. For example, even if a penalty drew the lowest strict liability level of $10,000 per violation, a failure to demonstrate compliance or carry over deficits could draw a penalty in the range of millions of dollars. Such a penalty is far too severe for an offense that does not signify actual emission of air contaminants beyond a statutory threshold.

Instead, penalties should be assessed on a per deficit basis, an approach which is authorized by the applicable penalty provisions of the Health & Safety Code and which ARB has already suggested. *See* Cal. Health & Safety Code § 38580(b)(3); proposed LCFS regulation § 95494(c). Unlike the extreme per day penalty provision, a per deficit penalty of $1000 is reasonable and more consistent with the nature of the violation.

WSPA therefore proposes a revision to the text of section 95494(c) as follows:

"~~Failure to demonstrate compliance at the end of a compliance period or carry over all deficits pursuant to section 95485(c) constitutes a separate violation for each day within the compliance period. Alternatively,~~ **<u>E</u>**ach deficit that is not eliminated or carried over **<u>at the end of a compliance period</u>** as required by section 95485(c) constitutes a separate violation of this subarticle for purposes of determining penalties pursuant to Health and Safety Code section 38580(b)(3), subject to a penalty not to exceed $1000 per deficit."

9. ***The requirement that refinery investment credits only be approved for reductions from projects with no increase in criteria or toxic emissions should be eliminated.***

WSPA strongly opposes the additional complex provisions that ARB has added to the refinery investment credit provisions. This added complexity and ambiguity will limit or eliminate legitimate GHG reduction projects from receiving credits. In particular, we oppose the requirement to approve credits only from projects with no increase in criteria or toxic emissions. It is complex, unnecessary, and inequitable when compared to other parties that are participating in the LCFS.

First, while seemingly simple in concept, there are volumes of regulations, guidance documents, and court cases related to air quality permitting where various methodologies are employed for determining what constitutes an increase.

For example, some of the questions that arise are: Is it only operational emissions or construction emissions? Is it only direct emissions from the source or indirect emissions? What if it adds personnel – will their driving trips be included? Should the increase be in terms of mass or concentration at sensitive receptors? What is the baseline for determining an increase? What years are picked for the baseline? What if there is an increase – but it is still within the permitted limit for that source or facility? How is it enforced after-the- fact – when other non-related changes at the refinery may occur that impact emissions year to year? The list can go on and on. This is a regulatory quagmire for ARB since any attempt to address or clarify these issues in the regulation could double the size of the regulation and create substantial litigation risk from various parties.

Second, this limitation is unnecessary because various regulations are in place to make sure emission increases either do not occur or are appropriately mitigated.

Under the California Health & Safety Code and Clean Air Act permitting requirements, there are already ample regulations that reduce the likelihood of an emission increase, and ensure that increases are within regulatory limits. Compliance with these programs is sufficient to ensure that no negative impact would arise from an increase in toxic or criteria air pollutants, should one occur, and thus limiting credits to GHG emission reduction modifications that do not result in <u>any</u> net increase of these pollutants is at best redundant and at worst unnecessarily restricts crediting when sufficient controls on increases are already in place.

For example, pursuant to California Health & Safety Code 39666, California has already adopted airborne toxic control measures to reduce toxic air contaminant emissions from non-vehicular sources such as refineries. Generally, refineries are also subject to Clean Air Act requirements, including permitting, which mandate that their emissions of criteria pollutants remain below a particular emission limitation. *See* 42 U.S.C. 7661c(a).

Increases of toxic and criteria air pollutants are already sufficiently regulated. ARB's requirement that refinery investment credits only be given when there is no net increase of criteria or toxic air pollutants is unnecessary and should be removed from the regulations.

Finally, this limitation is inequitable. There is no effort by ARB to address contemporaneous criteria and toxic emission impacts for any of the other credit generating parties in the regulation. Is this being addressed for innovative crude projects or modifications at alternative fuel facilities for improving their fuel pathway CI? Is this addressed for the construction of natural gas fueling stations or for receptors near the power plants that generate the electricity for new charging stations?

WSPA therefore requests that, at a minimum, ARB strike proposed section 95489(f)(1)(D) from the proposed regulations. Moreover, we ask that ARB eliminate the capital project requirement, any distinction based on historic refinery efficiency, and the complexity of a CI based on metric and references to petroleum products consistent with prior WSPA comments.

It is WSPA's position that ARB should make this process simple, allowing the applicant to demonstrate that a project or initiative implemented since 2010 will have a decrease in greenhouse gas emissions after 2016. ARB should also work with the applicant on appropriate, on-going monitoring provisions to ensure that the decrease is real, verifiable, quantifiable and sustainable. Refinements can be made to this process based on the applications submitted, but the complexity of the current proposal presents huge barriers to legitimate, creditable projects.

Policy/Technical Comments:

Section 95481- Definitions and Acronyms

The following terms are in the definition section, but not used in the rule. They should be removed.

- "Aggregation Indicator"
- "Biodiesel Blend"
- "Biofuel Production Facility"
- "Intermediate calculated value"
- "LRT-CBTS Reporting Deadlines"
- "Petroleum Intermediate"

The following terms are in the definition & acronym section, but not used in the rule. They should be removed.

- "AEZ-EF Model"
- "GTAP" or "GTAP Model"

WSPA recommends the following changes to section 95481 definitions (denoted in red):

"B100" – defined in "Biodiesel – does not need to be defined twice. Recommend either:

- ~~(6) "B100" means biodiesel meeting ASTM D6751-14 (2014) (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), which is incorporated herein by reference.~~

OR

- (8) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:
  - (A) Registered as a motor vehicle fuel or fuel additive under 40 Code of Federal Regulations (CFR) part 79;
  - (B) A mono-alkyl ester;
  - (C) Meets ASTM D6751-08 (2014), ~~Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, which is incorporated herein by reference~~;
  - (D) Intended for use in engines that are designed to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(11) "Biogas" means the raw methane and carbon dioxide derived from the anaerobic decomposition of organic matter in a landfill or ~~artificial~~ manufactured reactor (digester).

(12) "Bio-CNG" means biogas-derived biomethane which has been compressed to CNG. Bio-CNG has equivalent performance characteristics when compared to fossil CNG.

(13) "Bio-LNG" means biogas-derived biomethane which has been compressed and liquefied into LNG. Bio-LNG has equivalent performance characteristics when compared to fossil LNG.

(14) "Bio-L-CNG" means biogas-derived biomethane which has L-CNG. Bio-L-CNG has equivalent or better performance characteristics than fossil L-CNG.

(15) "Biomass" means …

(17) "Biomethane" is the refined end product when carbon dioxide and the impurities present in biogas are separated from the methane in the mixture, resulting in a product ~~about~~ containing approximately 99 percent methane content….

(69) "Producer" means, with respect to any fuel, the entity that made or prepared the fuel. This definition includes "out-of-state" where the production facility is out of the State of California and the entity has opted into the LCFS ~~production as long as~~ pursuant to section 95483.1.

(70) "Product Transfer Document (PTD)" means a document or set of documents that authenticate(s) the transfer of ownership of fuel from a regulated party to the recipient of the fuel and convey(s) the specific information required by this regulation.

The above correction to the PTD definition is a typographical correction only. WSPA has additional comments regarding this PTD definition below.

(75) "Reporting Party" means any person who, pursuant to section 95483 or 95483.1 is the initial regulated party holding the compliance obligation, and any person to whom the compliance obligation has been transferred ~~directly or indirectly~~ from the initial upstream regulated party.

The following terms are in the Acronyms section, but not used in the rule. They should be removed.

- "FFV"
- "FOA"
- "FPCOA"
- "GREET" (defined in CA-GREET acronym – duplicative)
- "ILUC"
- "TOER"

Section 95481(a)(3)(B) – recommend the following changes *(denoted in red)*:

Transfer of Oxygenate or Biomass-Based Diesel and Retaining Compliance Obligation. Section 95483(a)(3)(A) notwithstanding, a regulated party transferring ownership of oxygenate or Biomass-Based Diesel may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred oxygenate or Biomass-Based Diesel by providing the recipient at the time of transfer with a product transfer document that prominently states the information specified in 95491(c)(1).

Section 95481(a)(5) – incorrect reference *(denoted in red)*:

(5) *Effect of Transfer by a Regulated Party of Oxygenate to be Blended with Gasoline.* Where oxygenate is added to gasoline, the regulated party, with respect to the oxygenate, is initially the producer or importer of the oxygenate. Transfers of the oxygenate are subject to section 95483(a)(1)(C).

Section 95481(c)(2 & 3) – incorrect reference *(denoted in red)*:

(2) *Transfer of a Blend of Liquid Alternative Fuel and Gasoline or Diesel Fuel and Compliance Obligation.* Except as provided for in section 95483(a)(4)(C), on each occasion that a person transfers ownership of fuel that falls within section 95483(a)(4) ("alternative liquid fuel blend") …

(3) *Transfer of a Blend of Liquid Alternative Fuel and Gasoline or Diesel Fuel and Retaining Compliance Obligation.* Section 95483(a)(4)(B) notwithstanding, …

Section 95482 – Fuels Subject to Regulation

No comments.

Section 95483 – Regulated Parties

Section 95483.2 *Establishing a LCFS Reporting tool Account*

This section contains new regulations and establishes registration requirements, account management roles and duties, and an application submittal deadline. The proposed regulations allow for two Account Administrators (primary and secondary). The proposed regulations do not contain a definition for Account Administrator in the definition section but their responsibilities are defined in this section.

WSPA requests ARB include the definition of "Account Administrator" in the definition section (§95481).

Q. Regulated Party Miscellaneous Updates

Section 95483(a)(2)(A) - WSPA does not support inclusion of the requirement for the buyer to notify the seller as to whether a company is a producer or importer. The typical transaction is completed entirely with the seller's paperwork and the only buyer response would be to reject a term. No response implies acceptance after a customary 10-day period. This would create a huge burden on a transaction-by-transaction basis. If ARB is presuming this communication is done verbally, then how is it documented in order to show compliance? If the seller's contract passes the obligation on to the buyer, by default, can it be assumed that the buyer communicated their status to them? Can ARB post entity status on the website and enable this to be the communication tool by directing sellers to the website?

WSPA does not believe the requirement outlined in the first sentence above is necessary and opposes its addition to the regulation. The addition of the language makes a long, complicated regulation even longer and more complicated.

ARB is adding new language to an existing paragraph (§95483(a)(2)(E)) dealing with the transfer of diesel fuel and adding a new section (§95483(d)(3)) dealing with LNG that is re-gasified and then compressed. Here are WSPA's comments:

Section 95483(a)(2)(E) Regulated Parties for Gasoline and Diesel

ARB is proposing to add explicit and clarifying language to what is already allowed in the existing regulation. ARB has added a proposed definition for "Above the Rack" (§95481(a)(1)) and added new language to an existing paragraph dealing with the obligation transfer. The proposed language states:
"… A person, who is neither a producer nor an importer and who acquires ownership of Diesel Fuel or Diesel Fuel Blends from the regulated party above the rack, may become the regulated party for the Diesel Fuel or Diesel Fuel Blends if, by the time ownership is transferred, the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party…".

WSPA agrees with staff that any party who acquires ownership of Diesel Fuel or Diesel Fuel Blends above the rack may become the regulated party. However, WSPA does not believe the proposed change to the existing regulatory language is necessary.

Section 95483(e) Regulated Parties for Electricity [Note: WSPA has consolidated our comments on the electric portion of the regulation below]

As WSPA has stated numerous times in the past, we strongly oppose ARB's electricity provisions, and continue to propose that electricity <u>NOT</u> be part of the LCFS program. ARB should account for the GHGs from electricity separately and reduce the compliance obligation within the LCFS proportionally based on ARB's anticipated success of the roll-out of EVs.

The electricity provisions should be eliminated from the LCFS since it is a readily available fuel – in fact ubiquitous. Based on ARB's experience, the innovative market signal hoped for from the LCFS is not needed for this fuel. In fact, ARB is proposing to reduce the incentive funding to EVs based on successful consumer acceptance to date.

The applications for incentive funds are chronically over-subscribed; and moreover, this has all been accomplished without any credit generation revenue from the LCFS. Utility reports to ARB in 2012 and 2013 indicate that no revenue has been derived from credit generation; and yet, ARB is touting the popularity of EVs amongst consumers. Clearly, the LCFS credits have not contributed to consumer acceptance to date and should not be needed in the future.

Barring removal from the regulation, there are key issues related to the electricity provisions that need to be addressed include the following:

Credit Generation For Pre-LCFS Off-Road Electricity Applications: WSPA is opposed to this provision.

1) It is unclear whether ARB has the statutory authority to allow credit generations from sources that pre-date the LCFS.
   - The off-road sources that will generate credits under this provision were in existence prior to the development or implementation of the LCFS.
   - ARB's own projections in the ISOR Appendix B, Table B-19 show that Electricity usage for HDVs/Rail is expected to remain static between 2016 and 2020.
   - The generation of credits for pre-LCFS electric does not meet the intent of the LCFS. These credits do not:
     - o Reduce transportation fuel CI,
     - o Reduce dependence of petroleum,
     - o Reduce GHG emissions.
1) This proposal creates an un-level playing field.
   - "Rewards" status quo activities by allowing them to generate CI credits.
   - Sales of these credits results in a cross-sector subsidy (transportation fuel sector to the electricity sector)
   - Merely allows ARB to justify an infeasible LCFS reduction target.
     - o For example, the ARB estimates HDV/Rail credits will be range from approximately 35 – 59% of the total electricity credits between 2016 and 2020 (from ARB's illustrative mix of fuels, ISOR Appendix B tables B-18 and B-19).

Removal Of Direct Metering Requirement: WSPA opposes the removal of the direct metering requirement.
1) Its removal creates concerns related to credit validity:
   - Due diligence of credits generated from residential charging of EVs is extremely difficult, if not impossible.
   - There is increased probability of credit invalidation.
   - Credit validity is further eroded by:
     - o The proposed CalETC calculation methodology and,
     - o The removal of supplemental reporting by electricity credit generators.

2) This proposal creates an un-level playing field**:**

- ARB is picking "winners and losers" by allowing electricity providers to bypass the detailed application, reporting, and recordkeeping, and rigor required by providers of liquid fuels.

3) Does ARB have the authority to remove the direct metering requirements?
4) Does ARB have the authority to authorize the sale of credits from estimated fuel usage?
5) ARB should, at a minimum, guarantee the validity of such credits and hold transportation fuel providers harmless in the event the credits are invalidated, including not requiring regulated parties to replace invalidated credits used or purchased for compliance.

Inclusion of new Heavy Duty EERs

1) WSPA does not support the proposal to allow these sources to generate credits without accurately including them in the 2010 baseline.

2) We do not support the proposed EER values for electric buses, and have provided specific comments below. We are concerned there is not sufficient information to establish EER values for electric buses as proposed.

3) If ARB continues to move forward with the proposed electric bus EER, the application should be limited specifically to new electric buses of the type tested and not be extended to existing electric buses (e.g. cantilever buses) in service prior to the implementation of the LCFS.

More detailed comments related to ARB's electricity provisions are outlined below:

Credit Generation for Off-Road pre-LCFS electricity applications:

In ARB's ISOR for the re-adoption of the LCFS, ARB states:

" Providing an opportunity for credit generation for use of use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce the carbon intensity of the transportation fuel in California, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and simulate the production and use of alternative, low-carbon fuels."

WSPA argues that while this may be true for new off-road electricity applications, it is certainly not the case for pre-LCFS electrical installations. In addition, the majority (if not all) of the GHG reductions provided by these sources pre-date the LCFS and will not provide any of the opportunities identified above nor reduce GHGs in the road transport sector.

This provision does not reduce the carbon intensity of transportation fuels, but rather "rewards" status quo activities by allowing them to generate CI credits. In addition, the sale of any such credits results in a cross-sector subsidy from the transportation fuel sector to the electricity sector, with no GHG or transportation fuel CI reductions. The generation of credits by pre-LCFS electrical installation merely allows ARB to justify an infeasible LCFS reduction target.

Allowance of LCFS credits for electricity used in applications in place prior to 2010 will lead to a smaller reduction in transportation fuel CI and GHGs undermining the stated LCFS objectives. WSPA's position continues to be that we are against including credits for fixed guideway systems and electric forklifts unless they are also properly accounted for in the 2010 baseline. Under no circumstances is it appropriate to make credits available for systems and equipment, such as BART, that have been in operation for decades. If ARB insists on pursuing credits for these off-road sources, credits should only be generated for prospective alternative fuel projects that occurred after LCFS adoption.

Direct Metering: §95491(a)(3)(D)(1)(b):

The proposed rule eliminates the requirement that reporting of electricity dispensed to electric vehicles at residences must be based on direct metering. Instead, staff is proposing to allow the use of a "robust estimation method" developed by CalETC.

We continue to emphasize that credit generators should be held to the same set of standards as liquid fuel providers and not be allowed to estimate the fuel supplied for transportation purposes. Eliminating the direct metering requirements also increases the risk of generating invalid credits, which weakens the integrity of the entire LCFS program. In our opinion the credits obtained through the use of estimates are more suspect than credits generated from actual metered electricity usage.

There is also a fairness issue. Considering the minutia of OPGEE inputs, the level of detail required for liquid fuel reporting and the detail involved with obtaining a CI pathway (and the record-keeping requirements for some pathways) simply allowing estimates of electricity used for residential charging is inconsistent. ARB is picking "winners and losers" by not requiring similar degrees of rigor across the program.

Further, because credits must be verifiable, ARB lacks power to require entities to participate in the credit scheme without providing some level of certainty that credits validly represent the reductions they purport to represent. *See* Cal. Health & Safety Code § 38562(d)(1) ["Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, ***verifiable***, and enforceable by the state board …"] [emphasis added]. ARB should not remove direct metering requirements, which erode the ability to verify and validate credits, and lacks authority to authorize the sale of credits from estimated fuel usage, which cannot be verifiable under California law.

As regulated parties, we are concerned that any credits generated via estimation techniques are more susceptible to challenges and invalidation. ARB should require measures to increase the validity of credits and not erode the validity. Only verified credits should be allowed in the program. WSPA believes the utilities ought to provide enough incentives through LCFS credit revenue or other incentive programs to maximize the amount of direct metering deployed for charging. We continue to oppose the proposal to allow electricity producers to generate credits from unmetered residential EV charging.

Calculation methodology:

Although staff has posted a letter on the ARB website approving this method (dated April 5, 2012), there are insufficient details for us to adequately review and comment upon the methodology. Based on the limited information available, it appears that the method would assume that vehicles within a service area without direct metering would be used in the same fashion as those that do have direct metering. Closer examination of this approval raises many questions/issues as follows:

- The proposal requires the utilities to report data quarterly for EV charging that is metered. The intention is to use this data as a proxy for unmetered EV charging. What is the extent of the metered data? Will this assessment be done only on a regional utility basis because the driving and utilization patterns might vary from region to region? What is the percentage of the metered data relative to unmetered data? What discussions have occurred about the extent necessary to be statistically relevant? For example – one metered customer should not represent hundreds of unmetered customers in the calculation. Is it ARB's intention to post this data in a de-identified or aggregated manner for public review?

- The proposal then allows a utility that does not have the ability to compile and report their direct metered data to use a statewide average of the direct metered data that is submitted. This means that a utility can use a statewide average value for direct metering as a proxy for its direct metering information that will be submitted to ARB, which will in turn be used as a proxy for statewide unmetered charging. An embedded approximation like this for use in a broader approximation is hardly robust. Moreover, will ARB report on which utilities have direct metering data and which do not and why? At a minimum, any utility that lacks any directly metered data should be excluded from the estimation technique and the ability to generate credits. There is no guarantee that the usage patterns in one utility's region will be representative of the usage patterns in another region.

- To determine numbers of PEV customers, CalETC will obtain 'zip+4' PEV registration data from a data management firm that accesses DMV data, or data from other sources. First, what are the zip+4 data and will this data be posted on the website? Second, who is the data management firm and what controls do they have to ensure the validity of the data? Are they subject to ARB audit and jurisdiction? If DMV data is not used, what are the other sources? How can the data from these other sources be assured?

- Is data separately available for PHEVs and BEVs? What is the average and range of the directly-metered data? It would be important to understand the variation potential that exists to understand the potential error band in the unmetered data. Perhaps some safety factor based on a statistically significant lower range should be incorporated into the credit calculation.

- Vehicle owners who go to the trouble of installing a separate meter are likely to plug in more faithfully than those who do not and are therefore not representative of the entire fleet. This is particularly important for PHEV estimates. Are there any data with which to confirm that the results from the metered fleet can be extrapolated to the unmetered fleet?

- Is ARB accounting for metering in public and work place setting and adjusting the residential estimates as appropriate? Will ARB review the total credits generated by all EV charging and compare it to the DMV records to ensure charging estimates are not "double counting"?

- The data collected on vehicles with direct metering cannot be applied to the entire fleet of BEVs and PHEVs in an area without also confirming that the distribution of vehicles (by BEV/PHEV and by all-electric range) is the same between those with meters and those without. It is highly unlikely that this distribution would be the same. For example, a PHEV with a 10-mile electric range that was purchased primarily for carpool lane access would likely be under-represented in the sub-set of vehicles with at-home meters.

- How is double-counting of electricity usage prevented? If at-home charging for those vehicles without a separate EV meter is accounted for with this method, is it assumed that all of the public charging stations get full credit for that electricity? What if a vehicle owner only charges at public or work-based charging stations and rarely charges at home? Is that vehicle assigned home-based charging at the same rate as those vehicles with at-home meters?

<u>Excluding Supplemental Information:</u>

ARB is proposing to exclude some supplemental information now required in annual reporting. WSPA disagrees with this, particularly the exclusion of the number of EVs operating in a service territory. Without this basic piece of information, ARB will not able to cross-check reported electricity usage by EVs for reasonableness.

In fact, we suggest that the reporting requirements be enhanced to include not only the number of EVs in a service territory, but also the number of plug-in vehicles in various categories (i.e., pure electric vs. plug-in hybrids by range).

It is important to distinguish between pure battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV); and within each of those categories, identifying the distribution of vehicles by electric range. For example, data collected by the Idaho

National Laboratory on in-use driving patterns for the Chevrolet Volt and Nissan Leaf can be found at: http://avt.inl.gov/evproject.shtml#.

Dividing the all-electric miles by the number of vehicles reported at that website gives quarterly VMT per vehicle for Oct-Dec 2013. The BEV Leaf (~6000 miles per year if 4Q2013 numbers are forecast to a full year) is accumulating fewer miles on electricity than the PHEV Volt (~8000 miles per year).[1] Clearly, the limited range of the Leaf is resulting in much lower VMT than a typical new car, while the broader utility of the Volt results in greater overall usage and higher VMT on electricity. However, PHEVs with lower range would have fewer miles on electricity, while BEVs with greater range would likely have more miles on electricity. These results reinforce the importance of understanding the make-up of the plug-in fleet in a particular area to generate an accurate estimate of on-road electricity usage. In addition, it is important to continue monitoring recharging and electricity usage of these vehicles as the patterns of usage may change as the vehicles expand beyond "first adopters."

WSPA opposes the proposal to remove the Supplemental Information from electricity providers reporting obligations, including accounting of credits generated, sold, and banked and accounting of number of EVs known to be operating in the service territory.

While WSPA recognizes the confidential nature of credit generation in the LCFS, if electricity credits are based on estimated electricity usage rather than direct metering, the public has a right to know precisely how those estimates were prepared and the number of credits generated as a result.

H.D. EERs: §95490 Table 5

Staff has proposed changes to the heavy-duty EV EER based on electric buses operating in California. Similarly, staff has proposed EERs for heavy rail, light rail and trolley buses, and electric forklifts. WSPA cannot comment on these values without reviewing the data upon which they were based. In general, however, we reiterate our concern about allowing these sources to generate credits without accurately including them in the 2010 baseline.

It is unclear whether ARB has adequate information to establish EER values for electric buses as proposed, and recommend that ARB evaluate whether additional testing or other information is needed prior to publication of EER values. We do not support the use of the proposed EER values.

Specific concerns that we would like to raise include the following:

1. There is insufficient evidence available to show that the proposed EERs represent actual in service fuel economies.
    a. The test procedure for electric buses is incomplete. Key information such as the measurement of energy consumption is not adequately described to independently repeat the test.

   b. The Altoona Bus Test website does not have a published test procedure for electric buses and the test procedure posted on the website is dated 2006.
   c. It is not illustrated that the posted 2006 diesel bus testing procedure is applicable to electric buses.
   d. In the posted test results and on the Altoona website, there are caveats presented that indicate that the Fuel Economy tests "will not represent actual "in service" fuel economy but will provide comparative data" (see http://www.altoonabustest.com/bus-tests.htm).

2. Modifications to the testing protocols have the potential to impact test results, making them non-representative of in-service conditions:
   a. Both an acceleration and deceleration profile should be followed during testing – there is the potential for a biased comparison between buses without a set profile.
   b. Modification of the maximum speed during the commuter cycle testing from 55 miles per hour (mph) to 40 mph may not be representative of real world conditions.
   c. A control vehicle should be used in the testing to account for external factors.

We continue to stress that ARB has not given regulated parties adequate time or information to truly evaluate this proposal. Given the concerns raised and the short comment timeframe, we urge ARB to not include the proposed EER values for electric buses. If ARB continues to move forward with this proposal, the application should be limited specifically to new electric buses of the type tested and not be extended to existing electric buses (e.g. cantilever buses) in service prior to the implementation of the LCFS.

Section 95484 – Average CI Requirements

CaRFG Carbon Intensity

WSPA cannot find a reference to the carbon intensity for CaRFG in the regulation. This is important because it is the baseline against which the reductions are determined. In the existing regulation it is part of the look-up table. Neither can we find any documentation detailing how the CI was derived. WSPA requests that it be included in the regulation.

Section 95485 - Demonstrating Compliance

Credit Clearance 95485(c)(1)(B)2 – we continue to have concerns with the credit clearance proposal as summarized below:

- This provision only serves to 'kick the can down the road' and adds additional complexity to an already complex regulation.
- We question whether any parties will pledge credits to the credit clearance market knowing that parties will have more obligation added the following year.
- The proposal to include a 5% interest rate on carried over credits only exacerbates the issues with infeasibility of LCFS targets in later years of the program.

- This option does not address the infeasibility of the LCFS targets.
- It is not clear how ARB developed the $200 / credit price ceiling.
- We have concerns regarding the ability to perform any due diligence on the Credit Clearance Market credits. ARB should, at a minimum, guarantee the validity of such credits and hold transportation fuel providers harmless in the event the credits are invalidated; including not requiring regulated parties to replace invalidated Credit Clearance Market Credits.

Here are some suggested revisions:

WSPA proposes that participation in the CCM be voluntary. In order for ARB to determine whether or not to hold a CCM for a particular year, ARB could issue a "Call For Deficits" similar to the "Call For Credits" described in §95485(c)(3)(A) in order to inform their decision.

Section §95485(c)(3)(E)(5) – recommend the following additions *(denoted in red)*:

Regulated parties that have pledged credits to sell into the Clearance Market, and have not sold or contractually agreed to sell all their pledged credits, cannot reject an offer to purchase pledged credits at the Maximum Price.

Deficit Carryover (formerly Section 95488(a)(4))
WSPA objects to the removal of the Deficit Carryover provisions in the proposed regulations. There may be planning or operational reasons why a regulated party may wish to carry deficits from one year to the next. We request that this section remain in the regulation as an option for entities not wishing to participate in the CCM.

This would be accomplished by changing Section 95485 Demonstrating Compliance, (c) *Credit Clearance Market*, (1) by adding the following:

"(D) Deficit Carryover. Non-withstanding the above, a regulated party may carry over the deficit to the next compliance period, without penalty and without participating in the Credit Clearance Market, if both of the following conditions are met:

(A) The regulated party fully met its annual compliance obligation or participated in the Credit Clearance Market in the previous compliance period; and
(B) The number of credits retired for the current annual compliance period is at least equal to 90 percent of the current annual compliance obligation."

If this change is made the following changes would also be required to the proposed regulatory language:

Section 95485(c)(4) - Add the following to the first paragraph: "unless the party elected to exercise the Deficit Carryover provision.

And for 95485(c)(4) (A) change the definition of “total Deficits” to: “total deficits” refers to the sum of all regulated parties’ obligations for the compliance year that have not been met pursuant to section 95485(a) or the Deficit Carryover provision; and

Section 95485(c)(4)(B) The LCFS credit balance and the individual entity names should be treated as highly confidential because the release of this information could adversely impact business operations. The release of the LCFS credit balance would provide competitors and other LCFS credit market participants with short or long position knowledge. While that knowledge would enable the credit clearance market to perform as desired, it would allow for manipulation of the normal LCFS credit market. For example, if a party has to purchase a specified pro rata share of LCFS credits in the credit clearance market and is unable to, then the parties who have credits to sell after the credit clearance market is completed would have a financial incentive not to sell until the next credit clearance market and they would be aware of entities’ shortfalls. Rather than have positions posted publicly as noted in 95485(c)(4)(B)1. and 2., regulated parties would prefer to have a designated overseer within the California Air Resources Board to bring buyers and sellers together and preserve confidentiality of individual parties positions.

Section 95485(c)(5) – WSPA understands ARB is proposing to prohibit entities that have a roll-over deficit under the credit clearance approach from transferring/selling credits to another party until the deficit is “paid back.” WSPA understands this prohibition is only intended to apply to “separated” credit transactions and not to the transfer of obligation with physical fuel. We are requesting that ARB confirm this in writing.

Section 95486 – Generating & Calculating Deficits & Credits

Section 95486(a)(4)(A) – recommend the following change – to be consistent with existing regulation & §95486(a)(4)(B)(2) ***(denoted in red):***

(A) *Extended Credit Acquisition Period.* A regulated party may acquire, via purchase or transfer, additional credits between January 1st and March 31st (“extended period”) to be used for meeting the compliance obligation of the year immediately prior to the extended period. Credits acquired for this purpose are defined as “carryback” credits. All carryback credit transfers must be initiated in the LRT-CBTS by March 31st and completed by April ~~15~~30th to be valid for meeting the compliance obligation of the year immediately prior.

Section 95486(a)(4)(B)(2) – recommend the following change – to be consistent with existing regulation ***(denoted in red):***

The additional credit was generated in a compliance year prior to the extended period.

A regulated party electing to use carryback credits must identify the number and source of credits it desires to use as carryback credits in its annual compliance report submitted to the Executive Officer no later than April 30th of the year in which the additional credits were obtained.

A regulated party electing to use carryback credits must acquire and retire a sufficient amount of carryback and other credits to meet 100 percent of its compliance obligation in the prior compliance year. If sufficient credits are not available, a regulated party must minimize its compliance shortfall by retiring all credits purchased during the extended periods that are eligible to be used as carry back credits.

Section 95486(c) - Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly after data are reconciled with its business partner.

WSPA believes that the new proposed language is unworkable in its current form. WSPA supports the goals of staff of accurate reporting, and we support the new reporting provisions requiring an initial report followed by a 45 day reconciliation period. Section 95491 Reporting and Recordkeeping (a)(1)(A) calls for reporting parties to "work in good faith with their counter parties to resolve and fuel transaction discrepancies between the parties". WSPA supports this but notes that this does not ensure that there will not be any discrepancies between reporting parties. To be consistent with section 95491, WSPA believes the language of 85486 (c) should be modified to state:

(c) Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly <u>after its quarterly report has been filed and it has made a good faith effort to</u> ~~after data are~~ reconcile~~d~~ <u>its data</u> with its business partner

Section 95487 – Enhancements to LCFS Credit **Provisions**

WSPA agrees with the required use of the LRT for initiating and completing all credit transfers. However, WSPA questions whether ARB has a contingency plan for any prolonged outages that the system may experience. It may be appropriate to include a provision empowering ARB to put a temporary manual transaction process in place under such circumstances.

Section 95488 - Obtaining and Using Fuel Pathways

(a) Applicability-(page 51 – 52 of Appendix A)
Item (1)
WSPA is concerned about the short timeframe for parties to register and obtain a fuel pathway certification for those pathways that do not meet the requirements of 95488 (a)(1) given the two step board adoption process and the possibility of one or more 15-day packages. WSPA suggests a sunset date of one year after the effective date of the LCFS Re-Adoption regulations for **all** fuel pathways.

This can be accomplished by deleting the last sentence of the first paragraph 95488 (a) and the following paragraphs (1), (1)(A), (1)(B), (1)(C); and the following to the first paragraph in 95488 (a):

A fuel pathway certification or a registered fuel provider's use of a fuel pathway that was approved under the provisions of the previous LCFS regulation order may remain valid for as long as one year after the effective date of this subsection, and then shall be automatically deactivated.

Item (2)

For clarification purposes, assuming staff makes the above change, WSPA suggests the following phrase "both with approved physical pathways and those with physical pathways pending" be inserted into the revised first sentence of 95488 (a) ~~(1)~~ so it reads as follows:

A fuel pathway certification or a registered fuel provider's use of a fuel pathway both with approved physical pathways and those with physical pathways pending, that was approved under the provisions of the previous LCFS regulation order may remain valid for as long as one year after the effective date of this subsection, and shall then be automatically deactivated.

WSPA believes the above proposed change is consistent with the language in this subsection which uses the terms "in effect", "registered", and "certified"; but does not specifically address the initial demonstration of physical pathway.

(c) Specific Requirements and Procedures.

Item (4)

For increased transparency and because it is used to calculate the CI of denatured ethanol and the CI of CARFG for the 2010 standard, WSPA believes the regulations should contain a specific reference to the California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet.

This can be accomplished by adding a new paragraph (o) after paragraph 95488 (c) (1) (N) that reads as follows:

(N) A copy of the California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet showing the anhydrous and denatured ethanol CI values if the pathway is for ethanol.

California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet

Item (5)

WSPA recommends that several changes be made to the spreadsheet that staff has posted that is used to calculate the Carbon Intensity (CI) of CARFG and the incremental CI value that parties are directed to add to their CA-GREET 2.0 Pathway CI Result to account for the denaturant added to anhydrous ethanol.

Cell C13 (Line C) should be corrected to contain the correct updated ILUC value for corn ethanol. The proposed new value is 19.8g CO2e/MJ. Cell C13 currently has a value of

20.00g CO2e/MJ. The proposed CaRFG baseline number and the 2016+ standards in section 95484 should be updated to reflect this change.

WSPA believes staff is incorrectly characterizing the content of denatured ethanol based on the fuel specification rather than actual industry practice. The denatured ethanol standard allows up to 2.5 vol% denaturant, 1% water, 0.5% methanol and 1.4% other. Ethanol produced at ethanol plants does contain some water and methanol plus higher order alcohols. The reference cited in the spreadsheet only cites the current ethanol specification and gives no justification for treating the water, methanol, and other (which are higher order bio-alcohols) as CARBOB for the CI calculation.

Ethanol producers do not add more than 2.5% denaturant because exceeding this amount would result in having to assign less than 1 RIN per gallon of denatured ethanol (per EPA regulations) and ethanol buyers expect each gallon of ethanol to have 1 RIN attached to it. Thus WSPA agrees that 2.5 vol% should be used for the percent denaturant.

Ethanol producers also typically add water to ethanol up to the 1% standard. This water has no Carbon Intensity (CI) since it is not petroleum based. Theoretically, staff should divide the calculated ethanol vol% of anhydrous ethanol by .99 to account for this.

Ethanol producers do not add anything else to the ethanol. Any methanol contained should be treated as a biofuel (which it is) and not assigned a CI of CARBOB by subtracting the methanol content when calculating the ethanol content of denatured ethanol. The goal is to calculate the biofuel content. The “other” compounds are higher order alcohols which should also be treated as biofuels and not as CARBOB. Their energy content is greater than ethanol which makes up for the lower energy content of methanol. To not over calculate the CI of denatured ethanol staff should set the ethanol content at 96.5% (100% - 2.5% - 1%) or 97.47% (100% - 2.5% - 1%)/0.99 if staff elects to back out the water. Commercial denatured ethanol contains above 96% ethanol if not 97%.

To make the changes Cell C33 Line N should be changed to 9.698250% (10.05% times 96.5%). In addition, Cell C49 Line Y should be changed to 96.5% and Cell C50 Line Z should be changed to 3.5% (100% - 96.5%).

Making these changes including the iLUC correction will change the value of CaRFG from 98.18 to 98.14gCO2e/MJ. More importantly, it will change the 2010 denatured minus anhydrous value Cell 55 to 1.15gCO2e/MJ from the incorrect high value of 1.78.

Making these changes will also correct the calculated CI impact of denaturant in Cell C62 Line HH which ethanol producers have to use in calculating their new CI values per section 95488 or the regulations. For a 60 CI anhydrous ethanol the denaturant value to add would now be the correct value of 2.03gCO2/MJ versus the high value (when treating the methanol and other higher order alcohols as CARBOB) of 3.15gCO2/MJ. This is a decline of 1.12gCO2/MJ which is significant. If fact, the proposed regulations in this section at 95488(c)(4)(G)(2) Substantiality Requirements, consider 1.0 gCO2e/MJ to be a significant threshold for applying for a new pathway.

Item (6)
WSPA believes that the inclusion of regulated parties reporting CI's in addition to fuel producers, in section 95488(c)(6) *Relationship of Pathway Carbon Intensities to Units of Fuel Sold in California*, is unworkable. Regulated parties that are not fuel producers cannot reasonably be held responsible for the producer's assignment of a CI value. Nor should they be required to determine that the actual CI of the fuel is equal to or less that the CI value reported. This paragraph should just refer to fuel producers.

This can be fixed by changing the two references of "regulated parties" to "fuel producers" in paragraph 95488(c)(6)(A).

Evidence of Fuel Transport Mode- (page 84 – 87 of Appendix A)
Item (7)
WSPA suggests that all existing and submitted demonstrations of fuel transport modes be grandfathered into the LCFS Re-Adoption regulations. This could be accomplished by adding a statement to this effect to the second paragraph of 95488(e) Evidence of Fuel Transport Mode so it reads as follows:

A regulated party must submit the demonstration of a fuel transport mode to the Executive Officer within 90 days of providing a fuel in <u>California unless an initial demonstration of fuel transport mode was previously submitted and approved for that facility under the provisions of the previous LCFS regulation order.</u>

WSPA cannot see any benefit of having alternative fuel providers re-submit their initial or updated demonstrations of fuel transport modes to ARB. The changes in the LCFS Re-Adoption regulations do not have any impact on the validity of previous initial demonstrations of physical pathways under the existing regulations.

Revised Indirect Land Use Change (iLUC) Values

Indirect land use change (iLUC) estimates continue to be a source of uncertainty in the overall lifecycle GHG footprint of biofuels, and significant efforts to refine those estimates[2] have continued since ARB initially included iLUC in the LCFS. Although uncertainty in the estimates remains, WSPA agrees that iLUC effects for biofuel production need to be addressed in the context of the LCFS regulation, consistent with our comments on the 2009 LCFS rulemaking. In principle, the scientific basis for addressing iLUC in the LCFS remains sound, and improvements to methods and models for estimating iLUC values continue to be made.

In our 2009 comments WSPA also supported convening a Work Group with experts on both sides of the debate to ensure a balanced and transparent approach to further work on

[2] See, for example, proceedings from Coordinating Research Council workshops on life cycle analysis of biofuels/ transportation fuels held in 2009, 2011, and 2013 at http://www.crcao.com/workshops/index.html.

the issue. We applaud ARB for facilitating that effort, as well as the work group participants who devoted considerable time and energy to better define the issues around indirect effects. Although disagreements remained among experts about some key elements of the iLUC calculations (e.g., time accounting), there were other areas of agreement and recommended GTAP model improvements that have been incorporated by Purdue University and ARB (e.g., improved treatment of co-products for corn ethanol and soy biodiesel).

The detailed analysis of revised iLUC values is summarized in Appendix I of the ISOR. We have the following comments and questions on that analysis and the ensuing results.

1. A comparison of the current regulatory iLUC values and the proposed iLUC values is shown in the table below. Also shown are values presented at the November 20, 2014, workshop.

Comparison of Current and Proposed iLUC Values (gCO2e/MJ)			
Fuel Pathway	**Current Value (2009 Regulation)**	**Proposed Value (December 2014 ISOR)**	**November 2014 Workshop**[3]
Corn Ethanol	30	19.8	20.0
Sugarcane Ethanol	46	11.8	19.6
Soy Biodiesel	62	29.1	27.0
Canola Biodiesel	n/a	14.5	14.5
Sorghum Ethanol	n/a	19.4	12.7
Palm Biodiesel	n/a	71.4	46.4

Given the significant changes to both the GTAP model, which estimates the location and amount of land use change for a particular biofuel pathway and a given volume "shock," as well as the emission factors applied to the land use change (via the AEZ-EF model), it would be useful for ARB staff to identify how much of the ILUC changes in the table above are associated with GTAP model revisions versus emission factor revisions. Additionally, what is the basis for the changes between the November 2014 workshop and the December 2014 release of the ISOR?

2. It appears CARB is making a procedural change in how they plan to address iLUC. In the current regulation, iLUC values are part of the regulation (they are specified in the look-up tables). In the proposed regulation, the only mention of iLUC values is in §95486(b)(3)(B) which describes the credit calculation. The calculation requires incorporation of "a land use modifier (if applicable)" but those values are not found in the regulation.

[3] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/112014presentation.pdf

This opens the door to changes to key formulas outside of the rulemaking process and without opportunity for public comment. When regulations are amended, the California Administrative Procedure Act requires “basic minimum procedural requirements” for rulemaking, including giving interested parties an opportunity to comment on the rulemaking, and a response to public comments. *See Tidewater Marine Western, Inc. v. Bradshaw* (1996) 14 Cal.4th 557, 558; Cal. Gov. Code § 11346. But the proposed regulations attempt to avoid public discourse on potentially significant changes to the implementation of the LCFS by tying key values that are the rule’s backbone to calculations and data that could change at any time, with no explanation—essentially a *de facto* amendment of the regulation with no public process.

ARB must provide more certainty that key values and calculations will not change without public input. A possible remedy would be to add a table of iLUC values to the regulation.

3. Table I-1 of Appendix I summarizes the “shocks” used in GTAP to model iLUC emissions. For sugarcane ethanol, the table appears to indicate that 3 billion gallons of Brazilian production and 1 billion gallons of U.S. production were assumed. Is this a correct interpretation of the table, or do those volumes reflect the volumes consumed in Brazil and the U.S.? If the former interpretation is correct, what is the basis for these estimates, as we are not aware of large volumes of sugarcane ethanol being produced in the U.S.? What is the sensitivity of the model to changes in the split between Brazilian production and U.S. production?

4. The proposed iLUC values are based on an average of 30 model runs which used 5 different values for the yield-price elasticity, 2 sets of values for a yield adjustment for the cropland pasture land category, and 3 sets of values for the elasticity of crop yields with respect to area expansion (5 X 2 X 3 = 30 runs). ARB also prepared a Monte Carlo uncertainty analysis that consisted of up to 1,000 model runs for some pathways. Why were the means of the 30 discrete scenarios used to establish the iLUC values rather than the means of the Monte Carlo simulations?

5. As noted above, one of the parameters that was varied to establish the 30 model runs for the iLUC analysis was a yield adjustment for the cropland pasture land category, which is a new land category in the GTAP model relative to the 2009 analysis. This yield adjustment is intended to account for potential investments to increase the productivity of this land as it is brought into crop production. The discussion on page I-12 of Appendix I indicates:

> “However, Purdue researchers acknowledge that although they believe the effect is real, there is no empirical basis for the elasticity parameter proposed for this endogenous yield adjustment. In the absence of

> empirical evidence to estimate this parameter, staff used two sets of values for the runs employed for each biofuel analyzed here."

Given the lack of empirical data with which to estimate this parameter, what was the basis for the elasticities used in the analysis?

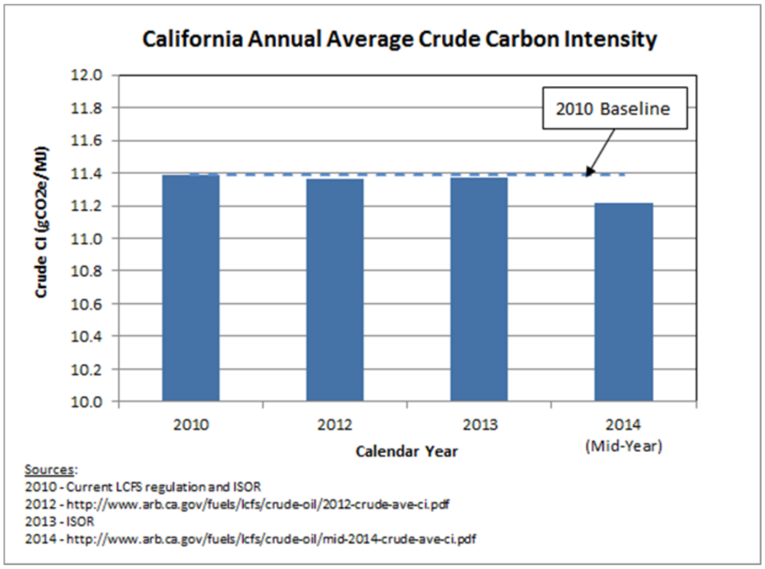
6. Land use change effects for cellulosic ethanol are discussed beginning on page I-18 of Appendix I. The discussion indicates that a value of 18gCO2e/MJ is proposed for cellulosic feedstocks, and that staff is continuing to work on model inputs for cellulosic ethanol from non-food crops and waste. The discussion further indicates that results will be published when the analysis is complete. Will an updated iLUC value be proposed for cellulosic ethanol via a 15-day change notice as part of the current rulemaking, or does staff envision another avenue to formalize this value? In what timeframe does staff expect to have an updated iLUC value for cellulosic feedstocks? Is the 18 gCO2e/MJ value only for farmed trees, miscanthus, and other purpose-grown cellulosic feedstocks, i.e., would waste products used for cellulosic ethanol feedstocks be assigned a land use change value of zero?

Section 95489- Provisions for Petroleum-Based Fuels

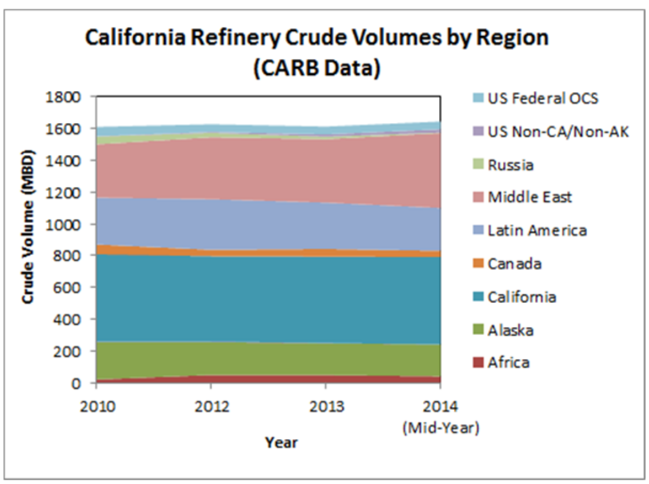
Section (a) – General - Annual Crude CI Calculation

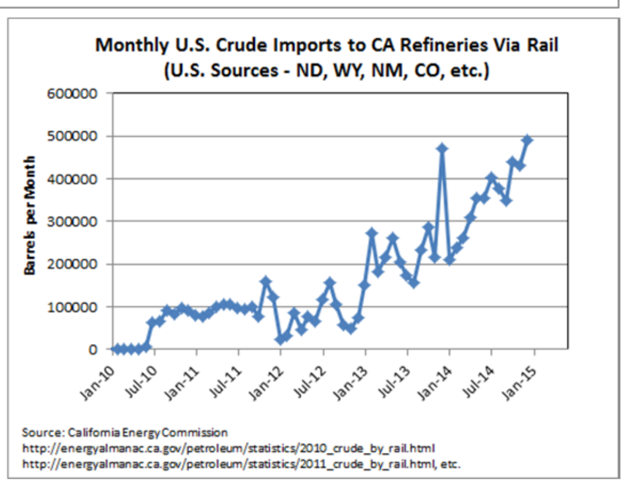
WSPA comprehends ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes the approach taken by staff in attempting to refine the crude handling provisions as part of the re-adoption rulemaking is consistent with that principle. However, we also believe that the degree of crude differentiation built into LCFS, to comprehend concerns over CA crude CI increasing over time, remains unnecessarily excessive and should be reduced. Our reasoning is as follows:

- The fundamental reason for these provisions in the rule was to ensure that the Average carbon intensity of the California crude slate did not increase over time. The available crude breakdown data for recent years (2011-2013) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable (see plot below).



Moreover, ARB data on crude volumes run in California Refineries show a decreasing trend in heavier Canadian crudes, while light Middle Eastern and U.S. mid-continent crudes ("U.S. Non-CA/Non-AK" in the figure below) have trended upwards. Furthermore, CEC data on U.S. mid-continent crude imports by rail show strong growth over the past three years that has continued through the second half of 2014.





- As a result, we believe that the justification drivers for installing, maintaining and expanding the current LCFS crude differentiation provisions have been greatly diminished since these provisions were implemented.
- Even if ongoing monitoring is necessary to ensure that staff's concerns that a heavier crude CI outlook does not materialize, the worst case scenario (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint. California's average crude CI may well remain constant, but global GHG emissions are likely to increase as the GHG emissions associated with transporting the crude exported from California (to non-optimal refining centers for processing) will be higher.
- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in the LCFS is resource-intensive for the ARB and equally burdensome for our industry in terms of the recordkeeping and reporting requirements it entails. In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining.

WSPA understands staff does not propose a fundamental change in the California Crude Average approach as part of this re-adoption package. We support staff's decision not to proceed with Refinery-Specific Crude Accounting for large, complex refineries and understand the rationale offered for doing so. We agree that there is no practical alternative to facilitate detailed individual crude breakdown in the pipeline crude blends that comprise a large part of refinery crude inputs in the state. We look forward to working with staff in the near future to examine potential options to modify the crude differentiation requirements in LCFS (post re-adoption), toward a less complex alternative that can hopefully satisfy staff's desire to track crude CI trends over time while reducing the compliance burden on our industry.

We note the proposed changes in the methodology for calculating the CA crude average to rely on CA on-shore crude production data (supplied by The Department of Conservation- DOC) and off-shore data (supplied by The Bureau of Safety and Environmental Enforcement- BSEE). This is in lieu of refinery-reported crude volumes that have been used for this purpose up to this point. Staff's rationale is simply that this is essential to improve the accuracy of the crude volumes used in the calculation of the CA Annual Crude Average. There is no backup support or analysis of the impact of the proposed changed in calculation methodology. More specifically, staff does not:

- Present data to determine how this change will impact the calculated annual volume averages to date. Staff merely indicates that total refinery-reported volumes for 2012 and 2013 closely match the volumes reported by CA field operators. We would recommend a more rigorous side-by-side comparison for 2011-2013 using the CA crude volumes estimated/reported by refineries versus the newly proposed utilization of DOC and BSEE data.

- Elaborate on the methodology that will be used to combine the in-state crude data with out-of-state crude volumes imported into California (both U.S. and foreign) to develop the overall annual CA crude average. Furthermore there is no indication that any potential discrepancies with the refinery-reported volumes will be investigated and reconciled.
- Recognize the difficulty that increased CA exports will entail should this methodology be adopted, dismissing such concerns by simply indicating that production volumes will be adjusted for exported crude volumes (should the need arise). Staff believes their proposal will work as long as all CA-produced crude is processed in CA, which is currently the case. However, staff's proposal appears to be short-sighted and inconsistent with the overall crude handling approach in the LCFS which, despite WSPA's input, is designed to drive increased crude exports to prevent CA crude average CI increases. Moreover, the same issues staff outlines in breaking down reported volumes of typical CA pipeline crude blends currently will be in play if/when staff tries to back out exported crude volumes out of the calculated CA annual average.

Many inputs are required to run the OPGEE model for a specific oil field and in particular for California fields, a number of important parameters, such as water-oil ratio, steam-oil ratio, and production volumes are available or are calculated from data published by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources. We encourage ARB staff to revise the OPGEE modeling to reflect actual realistic input values, such as for the steam generator feed water temperature, and we will work with ARB staff to provide more specific data on this and other model inputs for California crudes. ARB should pursue collecting the same composition, quality, and environmental profile details for other domestic and worldwide crudes as transparency and comprehensive, reliable, comparable data is critical to making effective and sustainable decisions.

Section (c) Addition of Incremental Deficits that Result from Increases in the Carbon Intensity of Crude Oil to a Regulated Party's Compliance Obligation (page 96 – 97 of Appendix A)

Item (1)
95489(c)(3)(B)
WSPA is concerned about the long lag time between the submittal of quarterly crude receipt data to ARB and the regulatory requirement of posting the prior year's Annual Crude Average carbon intensity calculation at the LCFS web site. WSPA requests that in order to facilitate obligated parties compliance planning and execution that ARB be required by the regulations to also post a quarterly Crude Average compliance calculation within 15 days of receiving the 1st, 2nd, and 3rd Quarter Compliance reports. This requirement should be added to paragraph (B) of 95489(c)(3).

Item (2)

95489(c)(3)(C)
The LCFS Regulations have been in a constant state of change since they were adopted by the board. WSPA believes that this uncertainty has and could continue to result in increased LCFS credit prices, compliance issues and difficulty in meeting the goals of the LCFS program. WSPA believes that a three-year cycle for not just updating Table 8 but of the LCFS regulations will have little benefit and add uncertainty to the program. WSPA suggests all LCFS regulatory revisions occur no more frequent than once every 5 years. This should not preclude CARB from adding new crudes to Table 8 on an annual basis. However, overall revisions to Table 8 or the OPGEE model should occur no more frequent than once every 5 years.

Section (d) – Credits for Crudes Using Innovative Methods

WSPA notes the revisions to the innovative crude provision, which help resolve several issues with the original provision that rendered it unworkable and thereby inhibited the use of these low-carbon production methods.

Most importantly, reducing the minimum threshold for carbon intensity reduction from 1.0 g/MJ to 0.1 g/MJ, or alternatively achieving annual emissions reductions of 5,000 MTCO2e or more, removes an impossibly high hurdle and might allow for a number of projects to receive approval. Allowing the producer to opt in as a regulated party and generate the credits rather than the refiner generating the credits provides the producer with a stronger incentive than the current regulation to apply to the Executive Officer for approval of the method. WSPA supports replacing the complex formula for calculating credits with default calculations as it will also aid applicants. Finally, WSPA supports the addition of solar and wind electrical power generation and solar heat generation as allowable innovative methods, as this could result in more successful applicants and therefore more available credits for regulated parties.

However, WSPA takes issue with limiting CCS as an innovative method to those instances where the carbon capture occurs onsite at the crude oil production facilities. CCS has the potential to generate a substantial number of credits under this provision, but many projects (and proposed projects) involve capturing carbon such as from power generation or other industrial emission streams not at the same physical site where the crude is extracted. This could seriously limit the potential of CCS under this provision and in general and stem the flow of much-needed credits. The capture of CO2 from a steam generator or other equipment at the oil production is desirable, but the overall cost of actual capture, sufficient volume, gathering and clean-up to a CO2 purity to allow for miscible injection and recovery at a reasonable economic scale is prohibitive in/through CCS as compared to capture from other large CO2 emission sources.

WSPA also objects to Section 95489 (d)(1)(B), which proposes that credit generation for CCS projects will only be allowed through the use of a Board-approved quantification methodology including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative method." Since applicants are required to be approved by the Executive Officer, WSPA proposes that quantification methodology for CCS projects should only require the approval of the Executive Officer, not the entire Board. WSPA would also encourage ARB to expedite the process for implementing the quantification methodology in order to incentivize applications under this provision.

Moreover, the proposal should include an option for Crude Production companies to apply for this credit for other GHG reduction projects above and beyond the four envisioned by ARB and included in the regulations:

- There are other technologies (e.g. solvent extraction) that may result in reduced energy usage and/or GHG from crude oil production.
- Limiting credits to solar and wind eliminates credits for other renewable energy, such as land fill gas, tidal power, etc.
- We feel the use of renewable electricity transmitted through an electricity grid should be eligible for this credit.
- We oppose the requirement that third parties providing either innovative steam or electricity must be co-applicants, especially given that co-applicants are not able to generate credits under the proposal.
    - Any recordkeeping or regulatory requirement would be more appropriately managed through contractual language between third party providers and crude producers.
    - Such a requirement may dis-incent applications for this credit and the use of the technologies ARB is trying promote.

Section (e) - Low Complexity/Low Energy Use (LC/LE) Refinery Provisions.

WSPA opposes the LC/LE Refinery provisions. We continue to believe it is inappropriate for ARB to be picking "winners and losers" among the refiners in the state and to effectively place those who have made the investments necessary to generate the volumes of refined product demanded by the market at a competitive disadvantage as far as LCFS compliance is concerned.

We oppose the LC/LE Incremental Deficit proposal, as we have consistently opposed crude differentiation in the LCFS program. If crude slate changes are going to be accounted for, WSPA opposes the treatment of individual refinery carbon intensities and particularly when such treatment is separate from, but additive to the statewide average.

In general, WSPA has the following concerns about the LC/LE approach to incremental crude oil CI calculation:

- The options are already overly complex for refiners and importers.
- It continues to differentiate between crudes and disadvantage one over the other.
- It could reward a refinery for past high CI crude use while penalizing a refinery with historically low CI crudes. It is not sensitive to energy security concerns.
- Allowing some refiners to opt-out of the industry-wide average approach creates a bifurcated market and introduces the potential for fraud given the chain of custody for crude and feed stocks is immensely complex and there is no uniform,

verifiable certification scheme. ARB's LCFS regulatory requirements should be fraud resistant.

If ARB moves forward with the LC/LE provision, we support the proposal to limit the LC/LE Refinery provisions only to transportation fuels produced from crude oil. However, the proposal as outlined raises some specific concerns:

- We believe the definition of "LE refineries" should be based on the lifecycle carbon intensity of the transportation fuels produced. The current proposed definition is based on total energy used at a refinery, and does not take into account life cycle energy use, e.g. whether the energy used per barrel of transportation fuels ***produced from crude oil*** for the LC/LE refiner is high or low compared to other refiners in the state. A LC/LE refiner that uses more energy per gallon of transportation fuel ***produced from crude oil*** should not be granted special treatment.
- In the ISOR ARB states that CARBOB and ULSD produced by LC/LE refiners have a CI that is approximately 5gCO2e/MJ less than the CI of other California refiners. However, it is not clear from the ISOR how ARB calculated the LC/LE refiners transportation fuel CI.
- Does the calculation of LC/LE overall CI include the transportation fuels produced from all feedstocks to the LC/LE refineries or the transportation fuels produced from crude oil? If the overall CI used to calculate the 5 gCO2e/MJ "adjustment" includes the processing of feedstocks other than crude oil, WSPA believes ARB should modify the adjustment to only take into account the transportation fuels produced from crude oil.
- With respect to Low Complexity-Low Energy Use Refineries seeking CI adjustments for the CARBOB and Diesel production from crude oil in 95489 (e), please explain how the volumes of CARBOB and diesel produced from crude oil versus transmix versus "intermediates" in 95489 (e)(2) are calculated? We request that ARB include a methodology for calculation of these different volumes in the regulation.
- In the ISOR, ARB staff stated these credits would only be used for compliance obligation by the LC/LE Refinery generating the credit, and would not be eligible to be sold or traded. However the draft regulation does not include any restrictions on how these credits are treated. The regulatory language should indicate that the sale and/or trade of any credits generated under the Low Complexity-Low Energy Use Refinery provisions is prohibited.

Section (e)(1) – incorrect reference *(denoted in red):*

- To be eligible for the credit and deficit calculations in section 95489(e)(3) and the refinery-specific incremental deficit calculation in section 95489(e)(4), a Low-Complexity/Low-Energy-Use Refinery must meet the criteria in section 95481(a)(55~~7~~) using the following equations:

Section (e)(2)(C) – if ARB does not remove the definition of "Petroleum Intermediate" recommend the following *(denoted in red):*

- The volume of CARBOB and diesel produced from Petroleum ~~i~~Intermediate feedstocks; and…

Formatting in the refinery-specific incremental deficit equations listed in 95489 (e)(4)(B) contains very little spacing between the individual portions of the “If” and “And” statements. It would be helpful for clarity if a line was inserted to increase the space between the "If" and "and" equations to avoid any confusion about subscripts in the upper equation versus potential superscripts in the lower equation.

Section (f) - Refinery Investment Credit

WSPA recognizes ARB’s efforts to allow credit for refinery investments as an element of LCFS GHG reductions. However, the proposed thresholds and restrictions risk eliminating most potential projects for arbitrary reasons. California refineries have a long history of investing in energy efficiency and optimization projects. This history is documented in the ARB energy efficiency summary for the refinery sector (http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf).

WSPA’s consultant, PetroTech Consultants, reviewed a recently-released Promotum report entitled, “California’s Low Carbon Fuel Standard: Evaluation of the Potential to Meet & Exceed the Standards” dated February 2, 2105, as well as another NRDC-sponsored TetraTech report, “ PetroTech provided comments that are summarized below on the two referenced report’s conclusions which were that ARB’s refinery investment credit option has significant credits to contribute to the pool.

A relevant subset of PetroTech’s comments are:

<u>Different base years used</u>

*Even though the base year for measuring CI reductions under the LCFS is 2010, the currently proposed regulation uses 2011-2013 refinery energy consumption data as the basis for estimating the CI of the petroleum refining process, not 2010. Furthermore, the regulation limits credit generation only to energy efficiency projects that are **permitted** after December 31, 2014. Credit generation is also limited by ARB to capital projects or those using renewable feedstocks that do not increase criteria or toxic pollutants. Capital projects normally take at least one year to implement. Thus, any energy efficiency improvements that were implemented in petroleum refineries between 2010 and 2016 cannot generate credits even though they have reduced the CI of the products.*

<u>Potential refinery energy efficiency improvements</u>

Refiners are in the business of transforming and delivering energy. Refinery energy use for the conversion of crude oil to finished products is their second largest cost behind feedstock (crude oil and blendstocks) acquisition. Energy usage and cost is monitored very closely within each refinery and has been for many years. Converting crude oil to *finished products requires energy. There is a theoretical minimum amount of energy required for the conversion that depends on the quality of the crude oil, product specifications and refinery configuration. More complex refineries generally require more energy to operate.*

Two recent studies commissioned by NRDC, one by Promotum[2] and one by Tetratech[3], have greatly overstated the energy efficiency improvements that are still available to the petroleum refineries in California. Both studies use the same 2013 CARB study of California refinery energy efficiency[4] as a basis. In this CARB study, the 12 largest refineries were required to report their 2009 energy usage as well as past and potential energy efficiency projects. This report stated,

> *"The estimated GHG emission reductions are approximately 2.8 MMTCO2e annually. Approximately half of the GHG emission reductions identified were completed before 2010 and are reflected in the 2009 GHG totals shown in Table IS-1. The other half of the GHG emission reductions are from projects that were completed during or after 2010, scheduled, or under investigation and are not reflected in the 2009 GHG values shown in Table IS-1."*

The total emissions reported in Table IS-1 were 31.4 MMTCO$_2$e per year. 50% of the projects were completed prior to 2010, so the remaining potential reductions for 2010 and beyond would be 1.4 MMTCO$_2$e per year. 80% of the projects were listed as competed or ongoing in the report, so the remaining reductions that could potentially be permitted after 2015 would result in a reduction of about 0.5 MMTCO$_2$e per year. The CARB report goes on to state:

> *"However, implementation of some projects may preclude the implementation of other projects that deal with the same equipment or processes. Therefore, these estimated reductions do not necessarily represent readily achievable on-site emission reductions."*

These identified projects with a total reduction of 2.8 MMTCO$_2$e per year were estimated to cost $2,600 million and result in annual savings of $200 for a simple payback of 14 years or a first year rate of return of about 7.7%. The highest rate of return projects would be implemented first, so the rate of return for the remaining projects would be lower.

The Tetratech report estimates that a 5-10 percent reduction in refinery GHG emissions from 2010 levels (1.6 to 3.2 MMTCO$_2$e per year) is easily attainable by 2020. Even their low estimate is higher than the CARB study estimates as a remaining potential. Tetratech justifies their higher estimate as follows:

> *"We note that these estimates [estimates reported in the CARB study] are likely conservative, given that (1) the information is based on self-audits and (2) the estimates do not include the off-site production of electricity, steam, or hydrogen,*

> *which is a potential major source of emissions and would be included in a life-cycle assessment."*

Regarding item (1) in the Tetratech justification, refineries continuously evaluate their energy use and invest in projects to improve energy efficiency. Most of the refining capacity in California is owned by publicly traded corporations. As such, their stockholders (including many public pension funds) expect a minimum rate of return on their investment. Management's fiduciary responsibility limits potential energy efficiency investment to those that meet the minimum return requirements, but also encourages them to invest in projects with good rates of return. The CARB report does state that some of the identified projects will not be implemented but does not state the reasons. There is no logical reason to assume that potential energy efficiency projects would be underreported.

Regarding item (2), refineries do not purchase any significant amount of steam except from co-located cogeneration facilities which are relatively new and efficient. Total electricity usage (both internally generated and purchased) is only 4% of refinery energy usage as identified in the CARB report. Purchased electricity is at grid average GHG levels, so measureable reductions in GHG emissions through purchased electricity are unlikely. The recently issued CARB report on energy efficiency in hydrogen production concludes that the merchant hydrogen plants in California are relatively new and very efficient. Future potential GHG reductions from merchant hydrogen production are only 1-2% of the energy used to produce hydrogen.

CO2 capture and storage for hydrogen plants is often quoted as an easily implemented GHG reduction technology for refineries. CO2 capture from hydrogen plants will not further the objectives of the current California LCFS. The California oil deposits are too shallow to benefit from CO2 based enhanced oil recovery techniques. Futhermore, the U.S. DOE has recently stated that widespread use of large scale CO2 storage facilities is not expected to be ready for dissemination until 2030[5].

The Promotum report estimates a potential reduction in refinery GHG emissions of 4.3 MMTCO_2e per year by 2025 (~14% reduction from 2010) primarily based on the added value of the emission credit.

> *"For refinery energy efficiency (EE) investments, it is assumed that at $100/ton, the incentive is sufficient to more than double the payback of EE, such that a reduction of 1.5% per year improvement in GHG emissions at refineries across the industry. We estimate that reductions from EE investments grow linearly from 2017 to 2025, reaching 4.3 MMT in annual reductions by 2025."*

According to the 2013 CARB energy efficiency report, 80% of the potential 2.8 MMT of annual CO2e reductions would have been implemented by now, leaving only 0.5 MMT of potential reduction projects that could be permitted in 2015 or beyond and eligible for the credit. The $100/MT of CO_2 credit is about $50 per barrel of crude. Although this *would change the rate of return for energy efficiency projects, the magnitude of this credit would not be sufficient to "more than double the payback of EE."*

Furthermore, there is no technical basis for Promotum's estimated total potential reduction of 4.3 MMT CO_2e per year. There is a theoretical amount of energy required to refine crude oil into saleable products. Neither the Tetratech nor Promotum studies recognize this fact. They both use arbitrary percentage reductions with no theoretical basis for the values.

Allowing full credits for refinery efficiency improvements implemented since 2010 is consistent with the objectives of the LCFS. As stated in the subject document,

> *"The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced."*

Refinery efficiency improvements since 2010 have reduced the carbon intensity of fuels produced within California relative to the base year of 2010 and should receive full credits under the program. Furthermore, all future projects, not only those that are permitted in 2015 or later should receive full credits. As highlighted by Promotum, the credits raise the rate of return and will cause more projects to be implemented, although not to the extent estimated by Promotum.

2. Promontum, California's Low Carbon Fuel Standard: Evaluation of the Potential to Meet and Exceed the Standards. http://docs.nrdc.org/energy/files/ene_15012801a.pdf
3. CARB, "Energy Efficiency and Co-benefits Assessment of Large Industrial Sources, Refinery Sector Public Report," June 6, 2013.
4. U.S. DOE, National Energy Technology Laboratory, "Carbon Storage Technology Program Plan," September 2013., http://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/Program-Plan-Carbon-Storage.pdf

Therefore, due to our industry's prior investments, the proposed limitations and restrictions staff has developed for the Refinery Investment Credit option are too high, create arbitrary inequities, or are inconsistent with existing programs and law.

We propose modifying the proposed section to address several of the restrictions and thresholds for the following reasons:

a. Limiting onsite increases of criteria air pollutants and toxics unreasonably excludes offsets of criteria and air toxic pollutants
b. 0.1 gCO2e/MJ threshold is too stringent and unfairly penalizes larger, more efficient refineries
c. Investments should not be limited to capital or onsite projects
d. Eligibility cutoff date does not recognize improvements made since program adoption
e. Biofeedstock 10% threshold is too restrictive and unfairly penalizes larger, more efficient refineries.

Incorporating criteria and air toxic pollutant controls in LCFS is misguided

California's long-standing framework of stringent air quality programs must remain the primary tool to regulate local and regional air pollutants rather than grafting co-pollutant measures or requirements onto the LCFS. The proposed limitation in attempt to address criteria and air toxic emissions is complex, unnecessary, and inequitable:

- Complex – there are volumes of regulations, guidance documents, and court cases related to air quality permitting where various methodologies are employed for determining what constitutes an increase. For example, some of the questions that arise are: Is it only direct emissions from the source or indirect emissions? Should the increase be in terms of mass or concentration at sensitive receptors? What is the baseline for determining an increase? What if there is an increase – but it is still within the permitted limit for that source or facility? How is it enforced after-the- fact – when other non-related changes at the refinery may occur that impact emissions year to year? This is a regulatory quagmire for ARB since any attempt to address or clarify these issues in the regulation could double the size of the regulation and create substantial litigation risk from various parties.

- Unnecessary – the CEQA process and robust air quality permitting processes are more than sufficient to reduce the likelihood of an increase, mitigate any increase, or ensure that the increase is within regulatory limits that are protective of the community and the environment.

- Inequitable – there is no effort by ARB to address contemporaneous criteria and toxic emission impacts for any of the other credit generating parties/mechanisms in the LCFS regulation (e.g., innovative crude projects or modifications, alternative fuel facilities applying for fuel pathway CI improvement, construction of natural gas fueling stations, or power plants that generate the electricity for new charging stations).

WSPA asks that ARB eliminate the requirement to address criteria pollutant or toxic emissions. ARB could adopt a monitoring approach similar to the approach in their cap and trade program to satisfy itself that its own non AB 32 air programs are effective. At a minimum, ARB should follow its own air pollution policies which provide refiners with the flexibility to offer mitigations offsetting any potential increase in criteria pollutants or toxics.

CI reduction project threshold of 0.1 gCO2e/MJ will unnecessarily eliminate legitimate projects

The threshold for efficiency projects of 0.1 gCO_2e/MJ is overly restrictive and potentially inequitable. For larger refineries, the absolute quantity of emissions reductions required to qualify a project (i.e., satisfy this threshold) will be larger and thus more difficult to meet. Some refineries may be more efficient (from a carbon intensity standpoint). This restriction may preclude such refiners from making further energy efficiency improvements.

Staff's proposed CI calculation in determining project credit also arbitrarily assigns credits based on product slate rather than GHG reduction. If project CI threshold is calculated based on volume percent of gasoline and diesel produced, a refinery's product slate will affect its ability to receive LCFS credits for energy efficiency projects. For example, if two hypothetical refineries have total emissions of 4 MMT each, but one produces 10% diesel, while the other produces only 5%, the number of tons of emissions reductions necessary to meet the minimum diesel CI target will be different for each refinery (40,000 or 20,000 tons).

Furthermore, the 0.1 gCO_2e/MJ reduction represents a substantially higher hurdle (in terms of absolute quantity of CO_2 reductions required) than is expected for other products' pathways in the regulation. This is due to the substantially larger throughput volumes of petroleum refineries and the fact that many petroleum refineries have already implemented energy efficiency improvements to lower their production CI. As a result, the use of a 0.1 gCO_2e/MJ may prevent refiners from making further reductions and, thusly, disadvantage them versus higher carbon intensity manufacturing processes for other products**.**

WSPA proposes eliminating the threshold altogether. If this is not feasible, an absolute value threshold (e.g. 1000 $MTCO_2e/year$) would incentivize reductions in a more equitable manner. In addition, ARB could also allow bundling of smaller projects to further incentivize energy efficiency where there may not be many large projects available.

Limitations on project type will eliminate valuable GHG reducing projects

The refinery investment mechanism should recognize non-capital but sustained improvements that reduce GHGs in addition to capital projects and co-processing. Many energy efficiency upgrades are considered non-capital. For example, replacement of equipment such as pumps, compressors, seals and blowers may include upgrades with lower greenhouse gas emissions. Insulation projects also may not be considered a capital project. These upgrades may not be considered capital expenses, and individually have relatively low greenhouse gas emission reductions. However, cumulatively, the cost of upgrades and insulation replacement can be significant, and the emissions reductions can add up. Since additional effort may be needed to upgrade rather than replace equipment "in kind", and to undertake insulation replacement, incentives from the LCFS program could help refineries take these actions.

Project eligibility should extend to early actors and at least to new construction.

The time limitation for eligibility of projects penalizes early actors contrary to AB 32 statutory provisions 38560.5(b)(1) and (3). We suggest that the deadline for project eligibility be based on the start of the LCFS program. At a minimum, WSPA believes that ARB should allow a refinery greenhouse gas emissions reduction project to be eligible if it is implemented (i.e., started up) after January 1, 2015, regardless of when permits for the project were initially filed.

Ensure that biofeedstock co-processing projects have a chance to qualify

Staff should reconsider and remove the proposed 10% biofeedstock threshold as it is inequitable. Percentage throughput limits are unfair to larger refineries, since the absolute volume of biofeedstock must be larger as facility size increases. We do not understand the basis for this threshold and believe that several potentially viable options would become essentially "non-starters" as a result.

Co-processing biofeedstocks is generally practical at far lower than 10% refinery throughput, especially for larger refineries. The proposed high thresholds for co-processing will discourage innovation and reduction in greenhouse gas emissions. WSPA recommends that this threshold be removed or that an absolute threshold (such as 1000 $MTCO_2e$/year) reduction should be used.

Other Comments

1) In the proposed section "95489(f) Refinery Investment Credit, the term "$Volume^{Total}$ *= total volume of product output in bbls (bbl)."* could be problematic to define (e.g., does it include only finished fuels or also refinery intermediates requiring further processing at another location? Are sulfur or butane production included?) WSPA would prefer a simple approach and, as an alternative to a potentially complex definition of refinery "products," WSPA recommends that ARB change the denominator in the term, "T = percentage of transportation fuel produced" *from* "total volume of <u>product output</u>…" to the "total volume of <u>crude oil and intermediates supplied to</u> the refinery (bbl)."

2) Currently in 95489(f)(1)(D) it states the refinery must annually replace a minimum of 10% of the fossil based feedstock. The regulation should clarify whether the 10% is based on volume of energy. WSPA would like ARB to provide a comparison of the 10% level to the 0.1g/MJ threshold for other projects. The 10% threshold seems to be a high threshold that will not help encourage such projects.

3) ARB should consider an option for CI reduction credits to be allocated more specifically to the units and products to which they apply (versus overall for the refinery).

Section 95490 – Requirements for Multimedia Evaluation

Please see the Legal comments section.

Section 95491 - Reporting and Recordkeeping

WSPA notes ARB's addition of the 45-day initial reporting deadline and subsequent 45-day reconciliation period. This will enable more immediate reconciliation of discrepancies between reporting parties.

We do not agree that unclear transmission of information on product transfer documents is a key cause of such discrepancies. The primary drivers for reporting discrepancies to date have been confusion regarding changes to regulatory requirements (particularly the nature and timing of the 2011 program amendments), and a steep learning curve for new regulated parties joining the program.

We object to the change proposed to the definition of Product Transfer Document (PTD) to refer to a newly created, single document rather than a collection of documents that transmit the required information. The term "PTD" has been used by several regulatory agencies over the years to refer to any document or documents that recognize a transfer of ownership/custody and includes certain required information. The very general nature of this definition has always been intended to allow flexibility in the execution of compliance and cause minimal disruption to operations. Establishing a narrow definition that requires a single, discrete document causes unnecessary additional cost while adding little or no benefit.

In the ISOR, ARB states the original transferor of fuel sold without obligation must report any export of that fuel by any subsequent owner or supplier. However, there is no regulatory language on this item in the draft text presented in Appendix A. Assuming that staff will develop language to reflect their intention in this regard and include it in the final regulation order, we have concerns about the practicality and fairness of this requirement. We find it impractical as it will be very difficult for fuel suppliers to ensure that the ultimate exporter communicates their activities backward through the supply chain. It also puts an unfair compliance burden on the original transferor by potentially taking credits away from that transferor because of another party's decision to export. It is understandable that ARB would want to track the export of such fuels, but the compliance cost/benefit of that export should accrue to the exporter and not to another party who has no control over their decision to export.

Section (a)(3) – WSPA does not believe the production facility ID and the Company ID should be included in all transaction documents. In many cases, multiple facilities and companies could produce biofuel with the same CI. Once these fuels are introduced into fungible systems where biofuels of the same CI cannot be distinguished, it should no longer be required to be tracked. This information should be included only for the initial transaction in the state of California (either production or importation), but not in further transactions, as the recordkeeping burden and the potential for mistakes and associated non-compliance penalties outweighs the perceived benefit of tracking this information.

Section (a)(7) - Provision (7) provides for quarterly and annual report corrections with proper substantiation to ARB, but it does not preclude enforcement. WSPA does not agree with this concept related to quarterly progress reports. Entities should be able to make changes to the quarterly reports with enforcement penalties provided the corrections do not material impact a credit transaction relying on the information submitted in the quarterly report. For example, there could be many, non-substantive changes to what is reported with no impact on credit balance – or perhaps the company does not complete any credit transactions between the completion of the quarterly report and when the correction is made. Promoting corrections to these quarterly progress reports is in ARB's best interest and imposing penalties will inhibit such corrections.

Section 95492 – Enforcement Protocols

Section 95493 - Jurisdiction

Section 95494 - Violations

Section 95495 – Authority to Suspend, Revoke or Modify

Section 95496 – Regulation Review

The proposed regulation includes a regulation review and a presentation to the Board by January 1, 2019. WSPA has several concerns with this section:

- The first concern is that this date is too late to effect change in the program. Since the compliance curve accelerates substantially in the final few years prior to the 2020 goal, it is highly likely there will be problems and issues with the program in this time period that will begin to manifest themselves beforehand. By the time the Board meets during 2019 to discuss the E.O. Review and determine if revisions to the regulation are needed, it will be too late.
- There is a substantial gap in time between the recent January 1, 2015 review and the January 1, 2019 review. The historical periodicity of regulation review has been more frequent, and as evidenced by several hearings to date held to make changes to the regulation, these more frequent reviews are needed to make changes to the program in a timely way.
- The list of issues that are identified as part of the review have been reduced from 13 items to 8. WSPA requests reinstatement of the items that have been proposed for removal from the review list such as:

  (3) Advances in full, fuel lifecycle assessments;
  (4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
  (6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
  (8) The LCFS program's impact on state revenues, consumers, and economic growth;
  (9) An analysis of public health impacts of the LCFS at the state and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB approved

method of analysis developed in consultation with public health experts from academia and other government agencies;

WSPA requests the ARB Board ask staff to revise the regulation to include the review items that were removed, and importantly, that the former Periodic Reviews be replaced with annual staff reports to the Board that provide a detailed synopsis of the health of the program, the challenges, and any need for program changes.

Section 95497 - Severability

No comments.

Appendix 1

Boston Consulting Group's Report – "Revised CARB Low Carbon Fuel Standard (LCFS) Illustrative Compliance Scenario," February 12, 2015

Revised CARB Low Carbon Fuel Standard (LCFS) Illustrative Compliance Scenario

February 12, 2015

THE BOSTON CONSULTING GROUP

Executive summary

In December as part of its Initial Statement of Reasons (ISOR) for LCFS re-adoption, CARB presented an illustrative LCFS compliance schedule (2016-2020)[1] and forecasted volumes of low-carbon intensity (low-CI) fuels allowing regulated parties to comply through 2020.

- BCG believes that these volumes and this schedule are overly optimistic and do not reflect a true "P50" scenario. It is more likely that volumes will fall short rather than exceed those predicted by CARB.
- Shortfalls in any of the fuel pathways would hasten the expected shortage of low-CI fuels and create a situation where there are not enough credits available to regulated parties for compliance

Absent detailed methodology from CARB, this document suggests reasonable volumes of low-CI fuels to consider when using the CARB compliance schedule

- The intent is to consider volumes with competing factors in mind:
  - Assume healthy growth rates due to technology advances and potential value of LCFS credits
  - Retain some conservatism based on high capital costs, uncertainty regarding vehicle availability, and a poor track record of low-CI fuel production versus expectations

The compliance schedule suggested by CARB using BCG forecasted volumes results in using all banked credits by 2020; the year 2020 credit deficit is 10.7 MT.

A 5.1% CI reduction in the total fuel pool is sustainable[2] by 2020 based on credits available through blending low-CI fuels (e.g. renewable diesel, biodiesel) and purchasing credits (e.g., elec., natural gas)

1. This document considers only the recommended "gradual" compliance scenario recommended by CARB in the ISOR. 2. Slowly using up banked credits up until 2020, and retaining the ability to meet the targeted CI reduction in a given year without relying on credits earned in previous years starting in 2020.
Source: CARB ISOR Appendix B, BCG analysis

Agenda

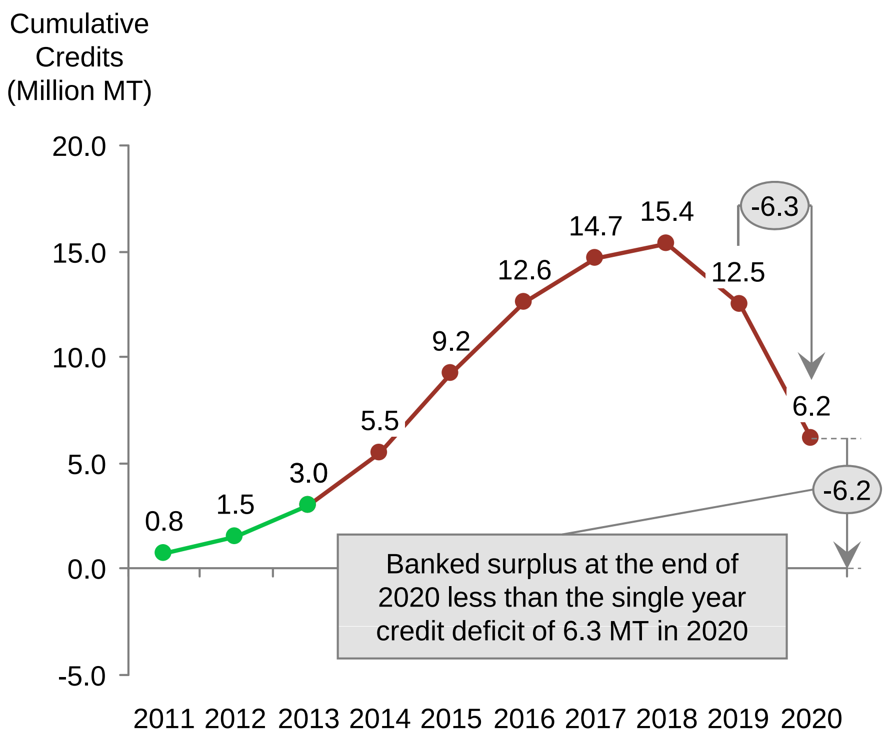
Overview

Comparing BCG and CARB forecasts

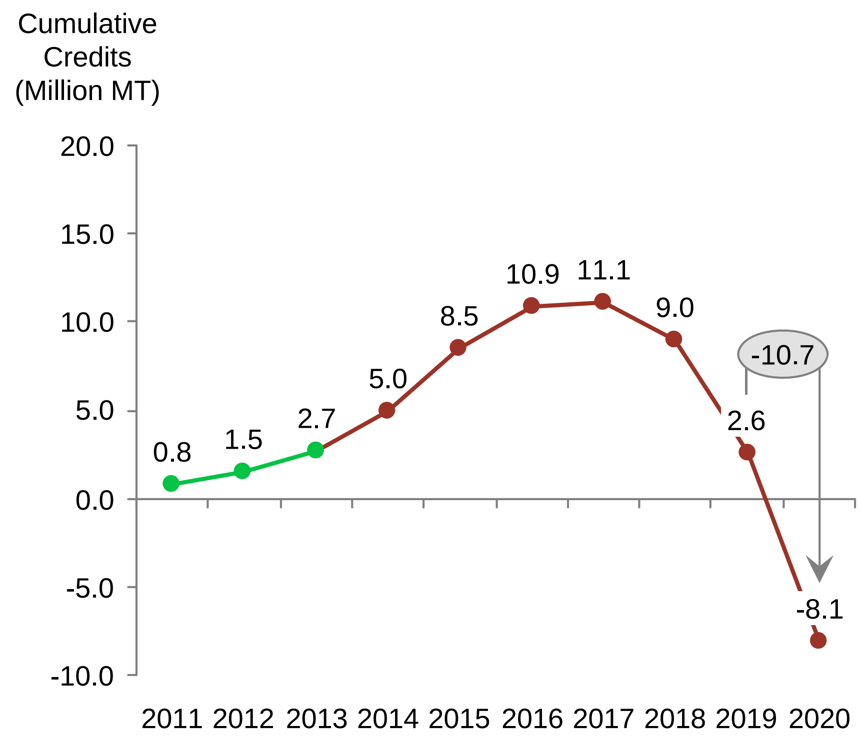
Methodology

Using same compliance schedule, BCG forecasts shows banked credits being exhausted earlier than CARB

CARB scenarios show banked credits in 2020 similar to 2020 annual deficit



BCG scenario shows banked credits gone by 2020, sizable annual deficits starting in 2018

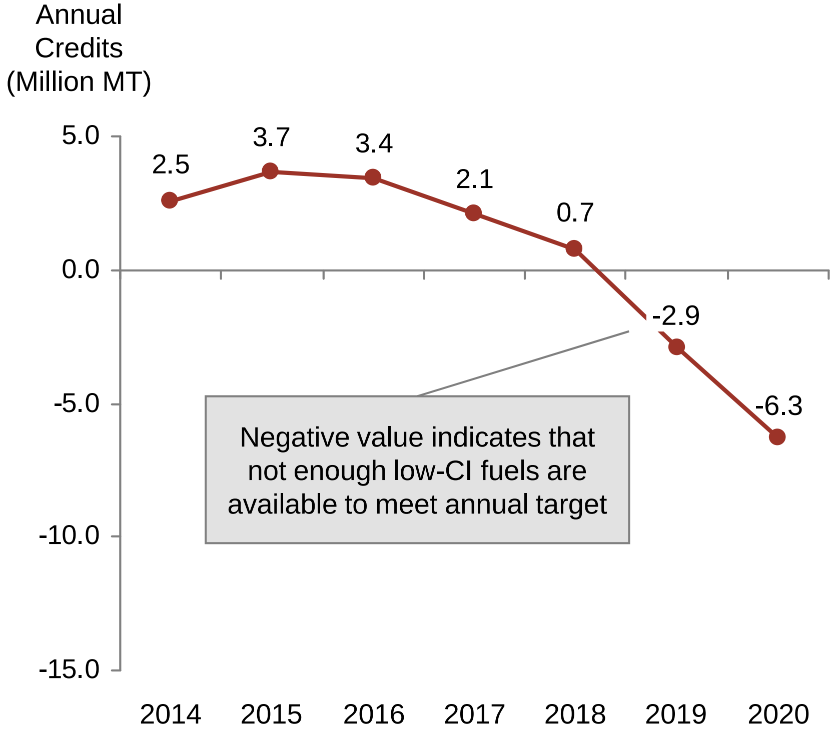


Forecasted Historical

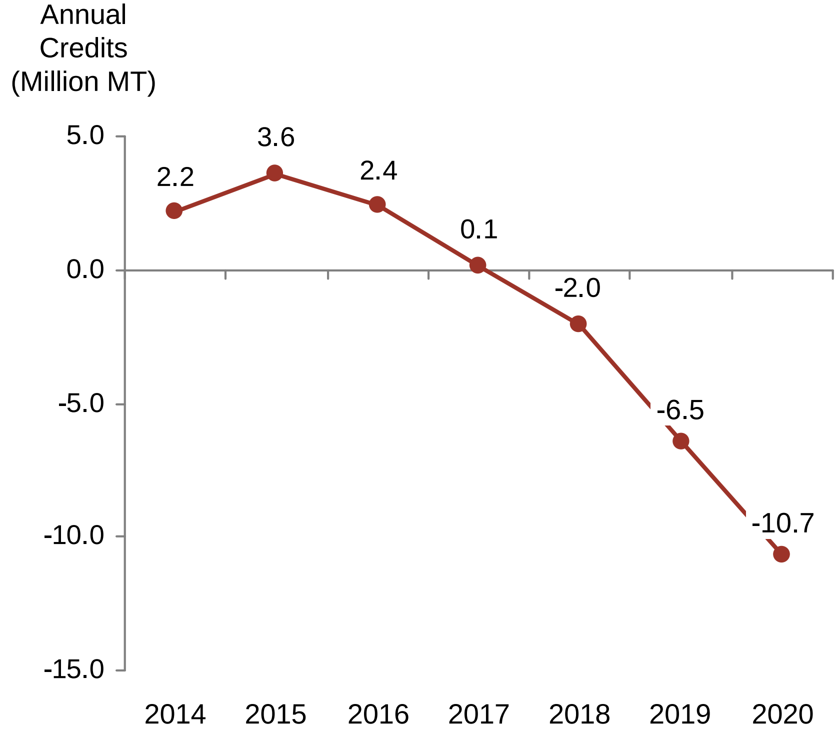
Source: CARB ISOR Appendix B, BCG analysis

BCG forecasts show 4.4 MT larger deficit[1] in 2020 versus CARB scenario

CARB scenario shows inability to meet CI target without banked credits starting in 2019

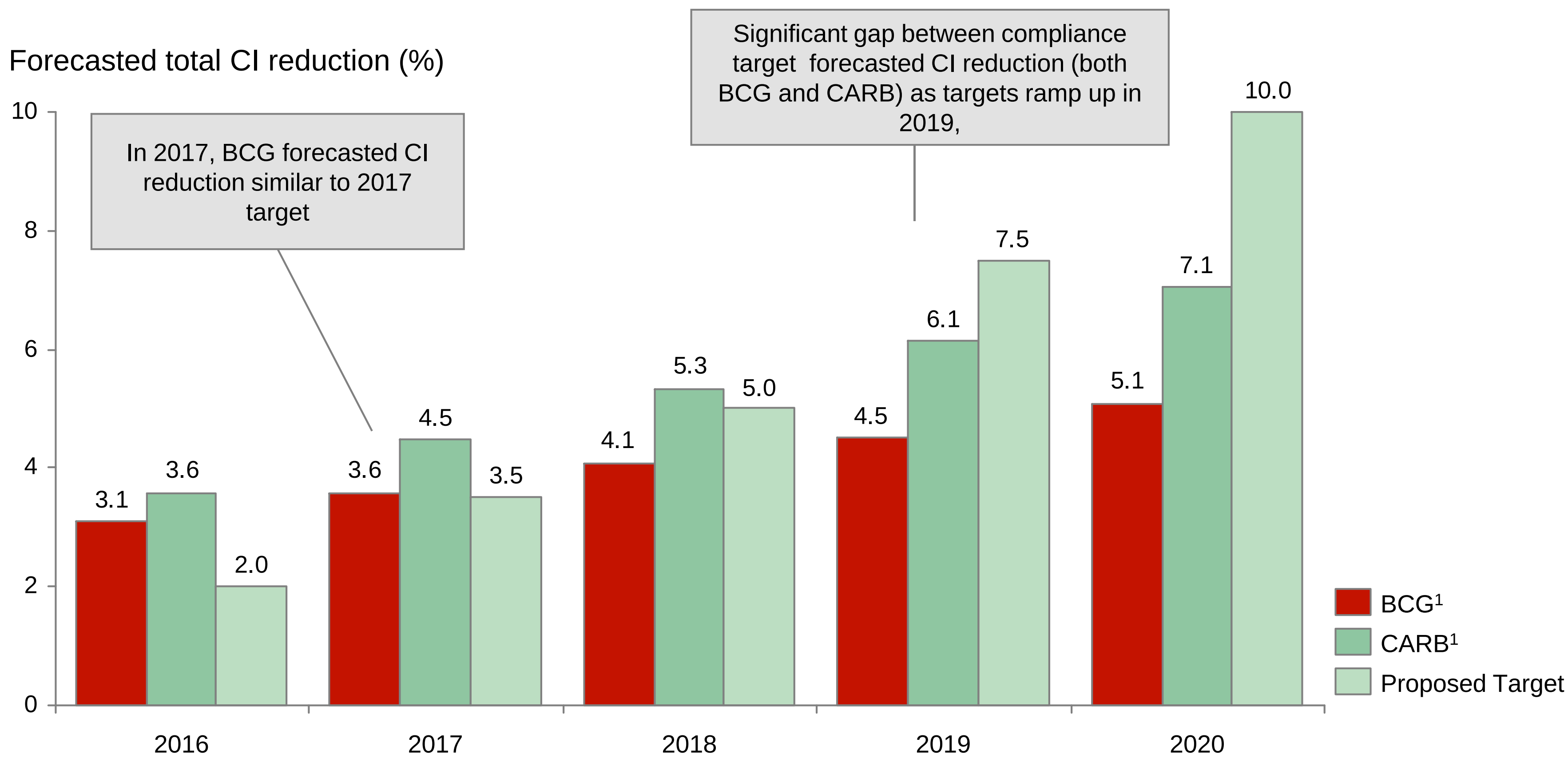


...while BCG forecasts show even more dramatic annual deficits



1. Number of deficits generated (from fuels with CIs exceeding target) less credits generated (from fuels lower than CI target) in a given year
Source: CARB ISOR Appendix B, BCG analysis

BCG scenario results in annual deficits by 2017

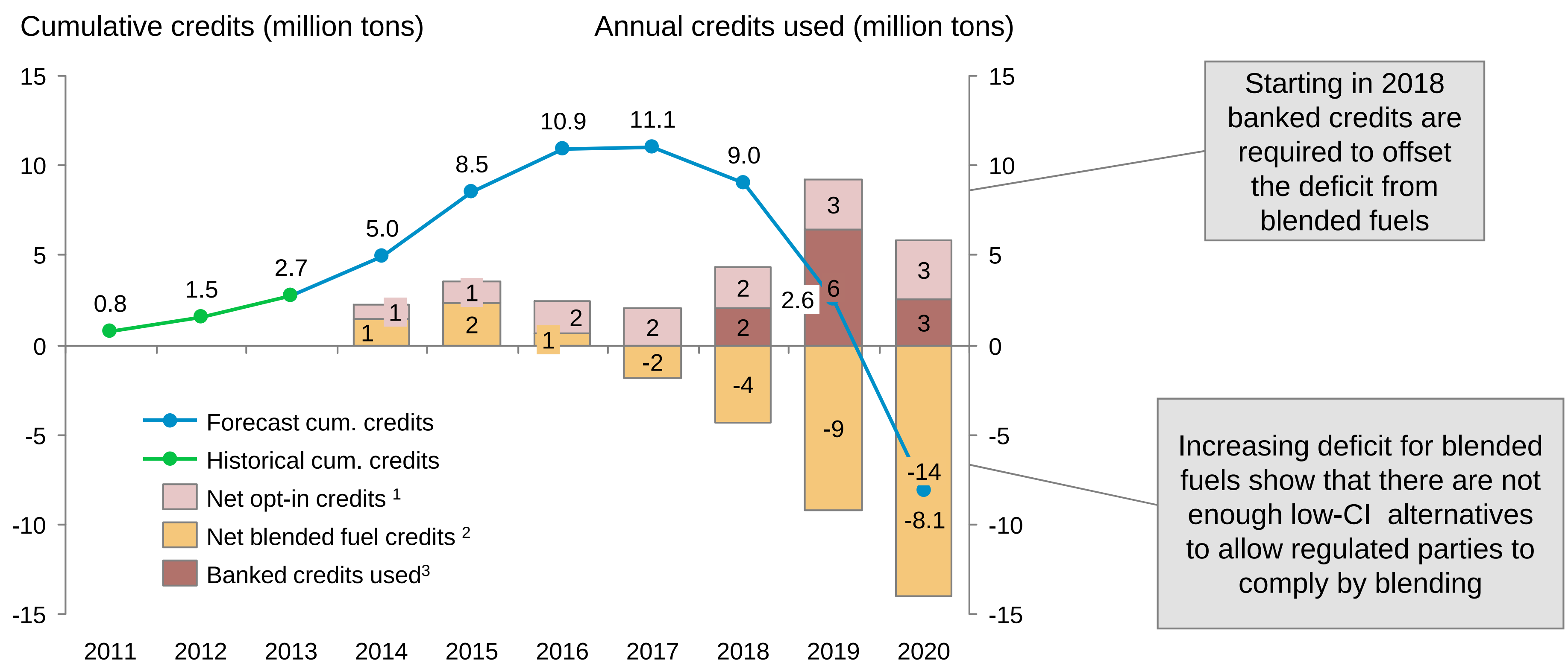


CARB scenarios fall short of CI targets starting in 2019

1. BCG and CARB forecasted CI reductions based on gradual compliance schedule recommended in ISOR Appendix B

Source: CARB ISOR Appendix B, BCG analysis

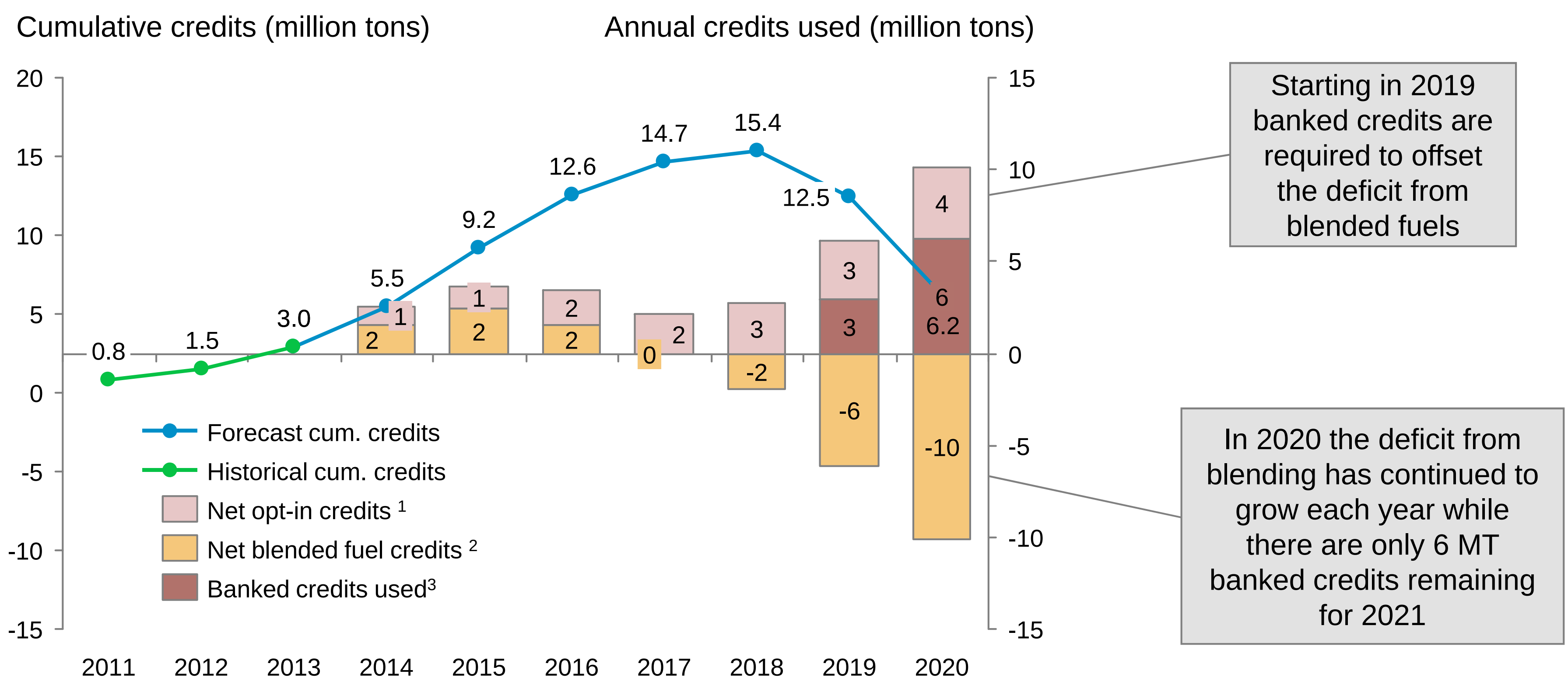
BCG forecast of compliance outlook relies heavily on banked and opt-in[1] credits



CI % reduction target	1.0%	1.0%	1.0%	2.0%	3.5%	5.0%	7.5%	10.0%

1. Opt-in fuels includes natural gas, electricity, and hydrogen 2. Credits minus deficits for blended fuel (e.g. CARBOB, CARB Diesel, ethanol, renew. diesel, biodiesel, etc.)3. Calculated as the difference between the annual deficits and credits generated from all fuels until no banked credits remain (2020 in this example) Assumes that if credits are greater than deficits, credits will be transferred/sold to regulated parties to achieve compliance.
Source: BCG analysis

CARB forecast of compliance shows similar outlook for net blended fuel credits by 2020

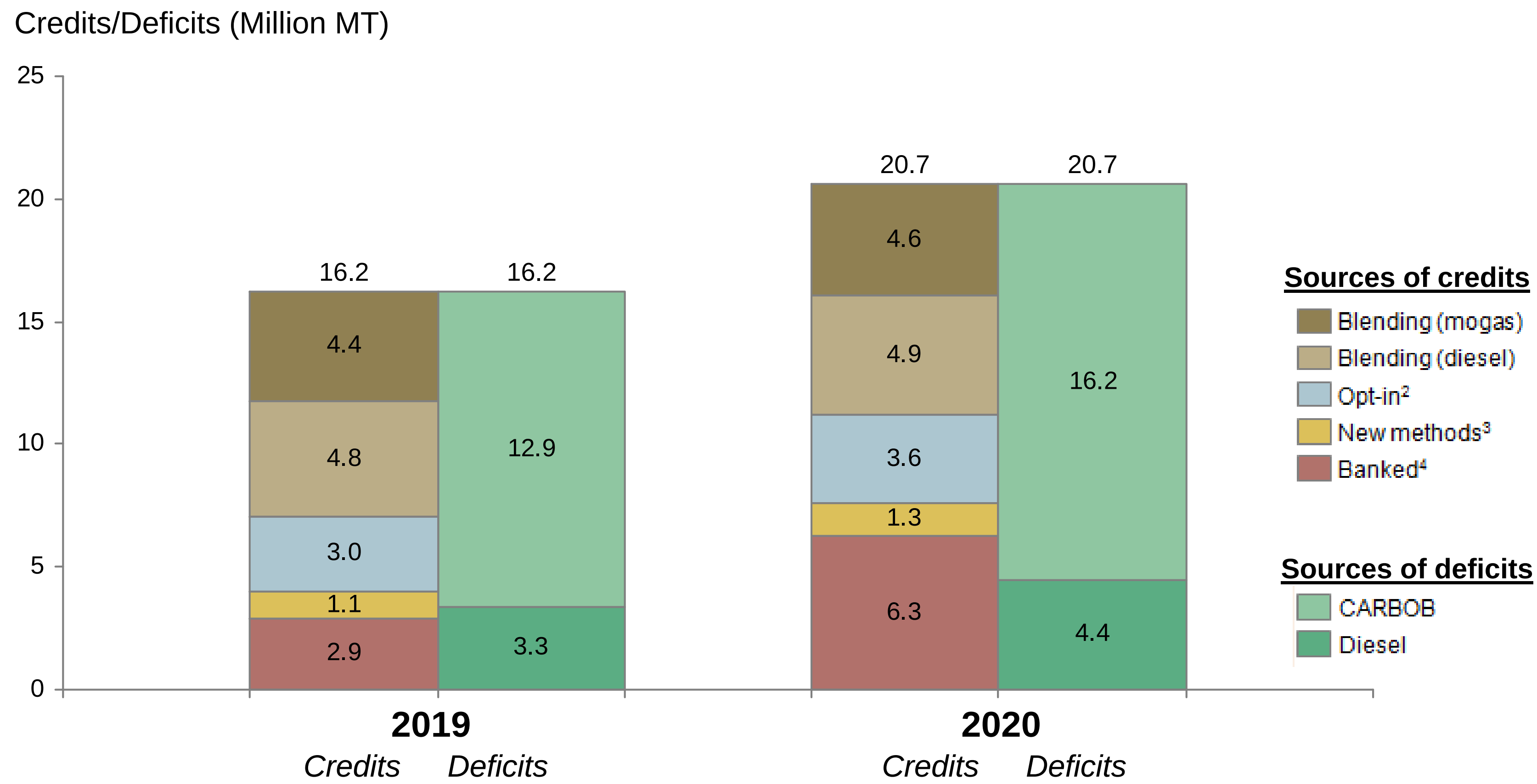


CI % reduction target	1.0%	1.0%	1.0%	2.0%	3.5%	5.0%	7.5%	10.0%

Uncertain whether all parties selling "opt-in" fuels will necessarily opt-in to the LCFS program

1. Opt-in fuels includes natural gas, electricity, and hydrogen 2. Credits minus deficits for blended fuel (e.g. CARBOB, CARB Diesel, ethanol, renew. diesel, biodiesel, etc.)3. Calculated as the difference between the annual deficits and credits generated from all fuels until no banked credits remain (2020 in this example) Assumes that if credits are greater than deficits, credits will be transferred/sold to regulated parties to achieve compliance.
Source: CARB ISOR Appendix B, BCG analysis

Based on CARB forecasts, transportation fuel credits[1] only offset 63% of deficits by 2020

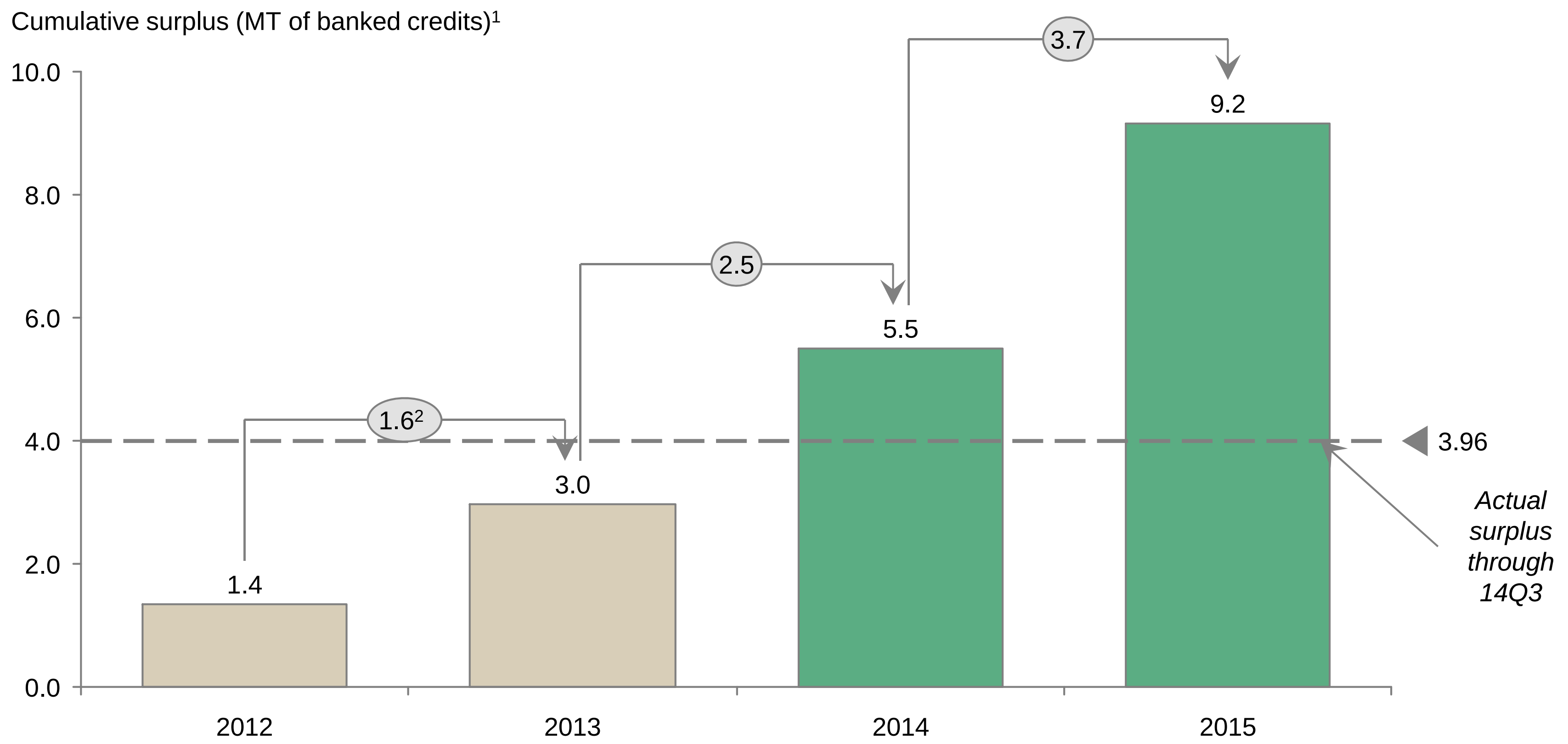


1. Transportation fuel credits consist of credits generated from blending fuels and from providing alternative fuels (opt-in credits) 2. Opt-in fuels includes natural gas, electricity, and hydrogen 3. New methods include refinery credits and fixed guideway credits 4 Banked credits required in that year to reach a balance of zero

Source: CARB ISOR Appendix B, BCG analysis

CARB assumes surplus will triple during 2014-15

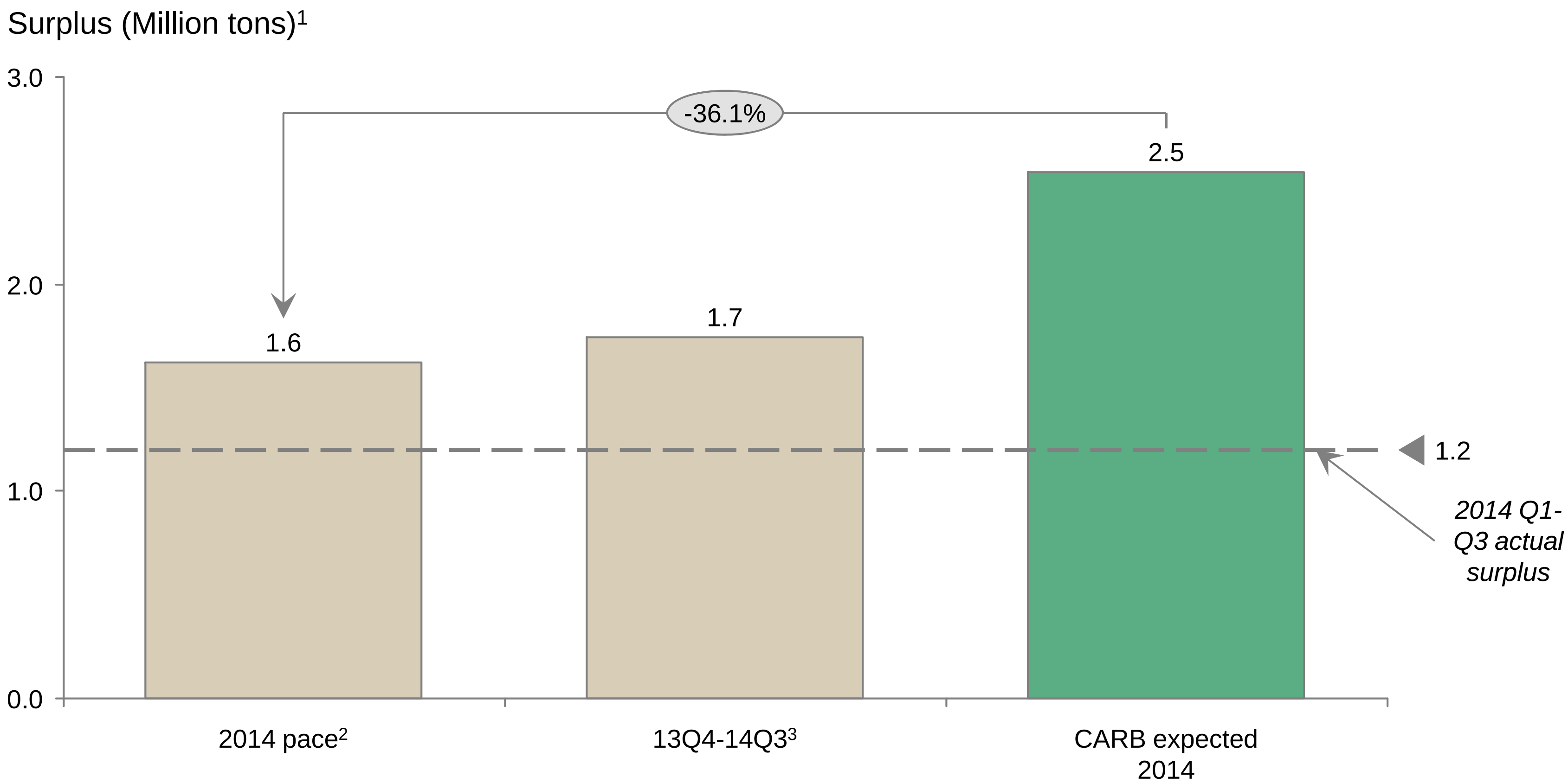
Near term growth likely overestimated by CARB forecasts



Even with flat CI reduction target (1%), CARB assumes high growth in low-CI fuel volumes over next 15 months

1. Credits less deficits in CARB "base case" scenario. 2. Surplus in CARB model is 1.7 MM credits even though CARB quarterly data indicates a surplus of 1.3 MM credits.
Source: CARB ISOR Appendix B, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

...but with three quarters of data available for 2014, credit surplus on pace to be 36% below CARB forecast

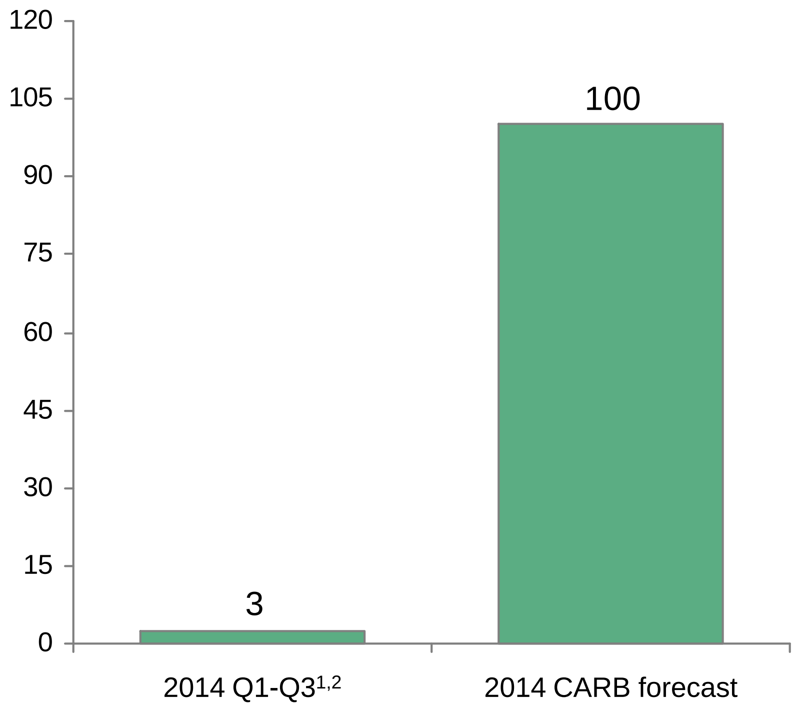


1. Credits less deficits in CARB compliance scenario. 2. Total surplus for 2014 if 4th quarter surplus is same as average of first three quarters. 3. Surplus for trailing four quarters (13Q4-14Q3) of available data.
Source: CARB ISOR Appendix B, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

Large gaps exist between CARB forecasts and volumes through the first three quarters of 2014

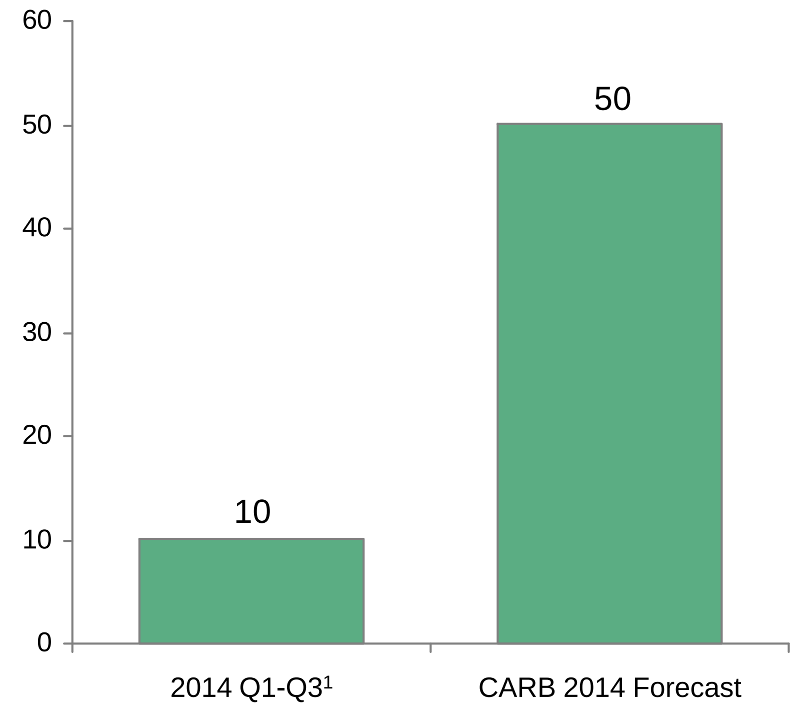
CARB continues to predict large cane ethanol volumes in 2014 contrary to data

Sugarcane ethanol imports to California (Million gal)



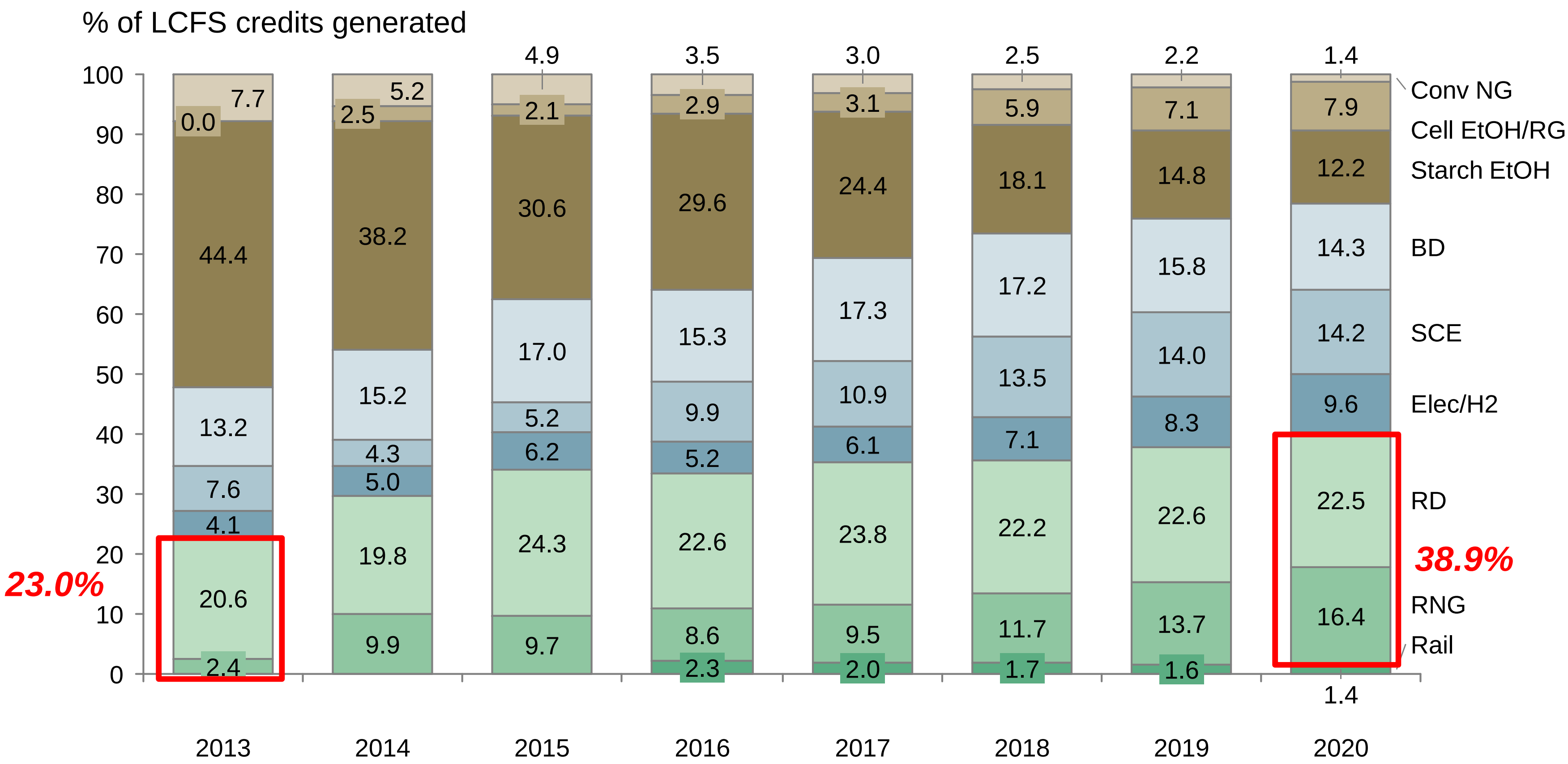
Renewable natural gas another pathway lagging expectations

Renewable NG generating LCFS credits (Million gal DGE)



1. Includes data as published by CARB as of January 20, 2015). 2. Census data indicates that no volumes have entered California from Brazil since January 2014
Source: CARB ISOR Appendix B, CARB quarterly LCFS data

CARB forecasted credits highly dependent on low-CI diesel



If RD/RNG credits fall below CARB's optimistic expectations, program will quickly become unsustainable

Source: CARB compliance scenario workshop

Agenda

Overview

Comparing BCG and CARB forecasts

Methodology

What are the differences between the CARB and BCG forecasts?

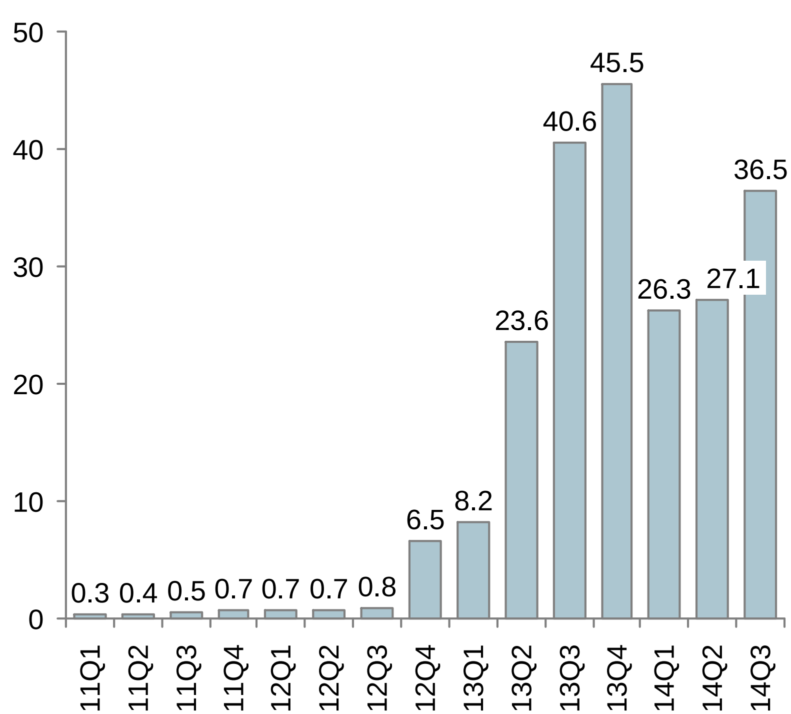
#		*Reasons for adjusting forecast*	*BCG 2020*	*CARB 2020*	*Cumulative impact by 2020 (MM Tons)[1]*
1	**Renewable diesel (RD) volumes**	Renewable diesel volumes to California have grown due to shipments from Singapore. However, blending constraints are expected to keep California volumes near 5% of the blended diesel pool.	200 MM Gal	400 MM Gal	(6.0)
2	**Refinery credits**	A difficult regulatory environment for new projects and the expected value of these projects for most refiners make it unlikely that any of these credits would be realized through 2020.	0 MT	1.1 MT	(3.2)
3	**Sugarcane ethanol (SCE) volumes**	Actual volumes from Brazil have declined and industry forecasts of Brazilian sugarcane imports to the US have moderated since 2012. California has not imported sugarcane ethanol since Jan 2014.	235 MM Gal	450 MM Gal	(1.9)
4	**Renewable natural gas**	Without detailed market information, BCG uses CARB's expected growth in RNG usage, but delays the start of the rapid growth from 2014 to 2015	180 MM DGE	240 MM DGE	(1.3)
5	**Total gasoline demand**	BCG uses the EIA AEO 2014 forecast for the supply of motor gasoline (averages -0.6%) vs. CARB's assumption of an annual 1.1% decline.	14.0 B Gal	13.6 B Gal	(1.0)
6	**Electric vehicle availability**	After CARB and BCG updated their EV forecasts based on current market information, the differences between the two forecasts are relatively small.	1,337 GWh for LDVs	1,629 GWh for LDVs	(0.6)
				Total impact	***(14.0)***

1.Decrease (or increase if negative) in banked credits through 2020 using the BCG forecasted volumes versus the CARB forecasted volumes 2. Appendix B of the ISOR indicates a median case of 587 million DGE and 61% RNG in the text while the table/model results show 300 MM Gal DGE with 80% RNG.
Source: BCG analysis

1 Renewable diesel volumes in California have increased, but will be limited by blending constraints

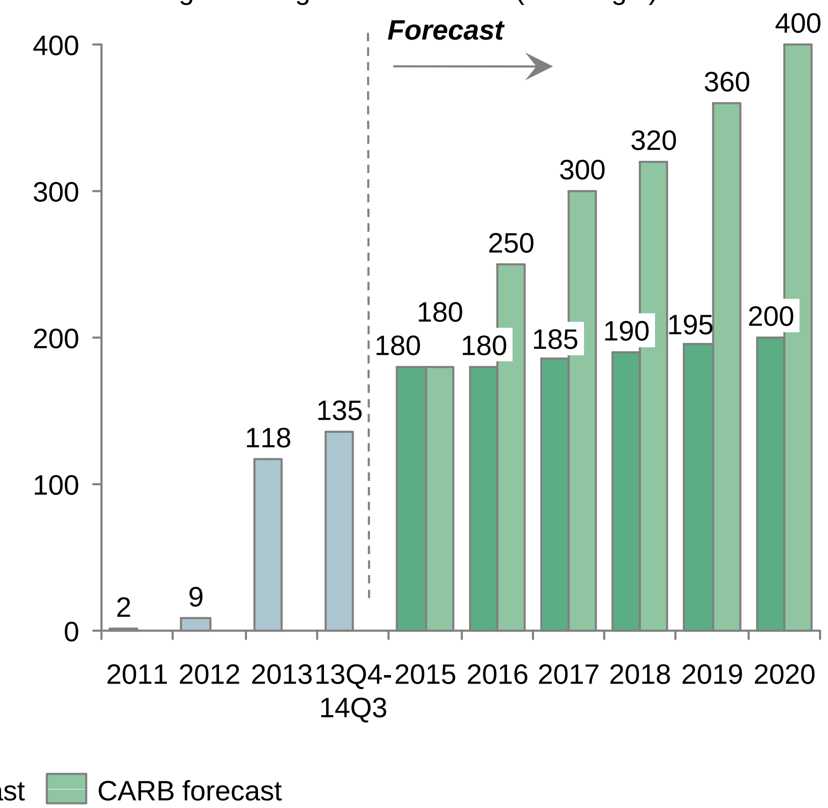
RD available to California has increased in the last few quarters

Historical RD volumes in California (Million gal)



BCG assumes that regulatory issues will limit RD blends to ~5% through 2020

RD volume generating credits in LCFS (Million gal)



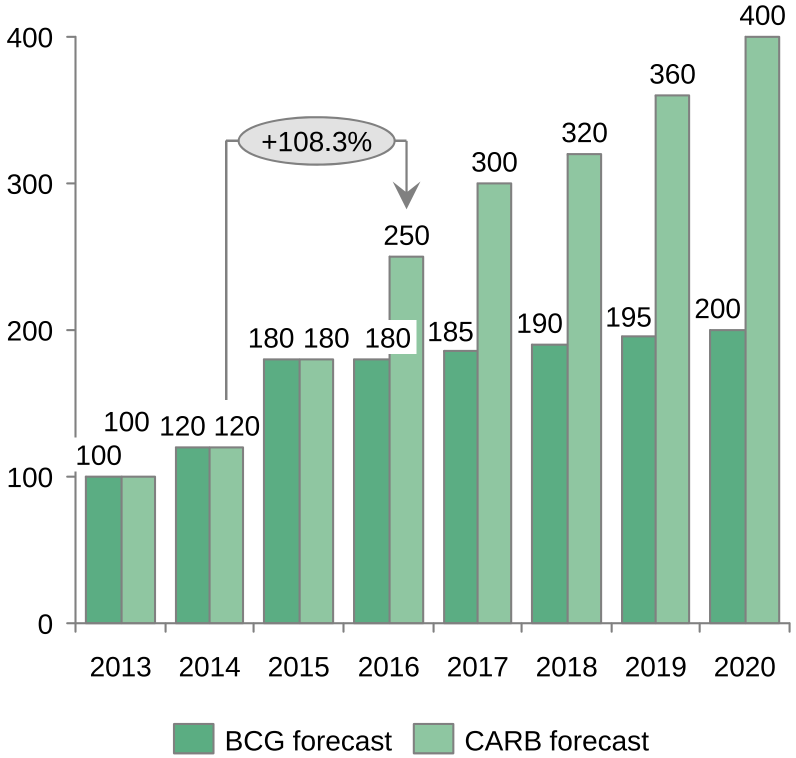
Source: CARB compliance scenario workshop, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

Even if blending issues resolved, renewable diesel volumes would still be limited due to available RD supply[1]

This is a sensitivity case to evaluate the renewable diesel availability should RD blending logistical issues be resolved

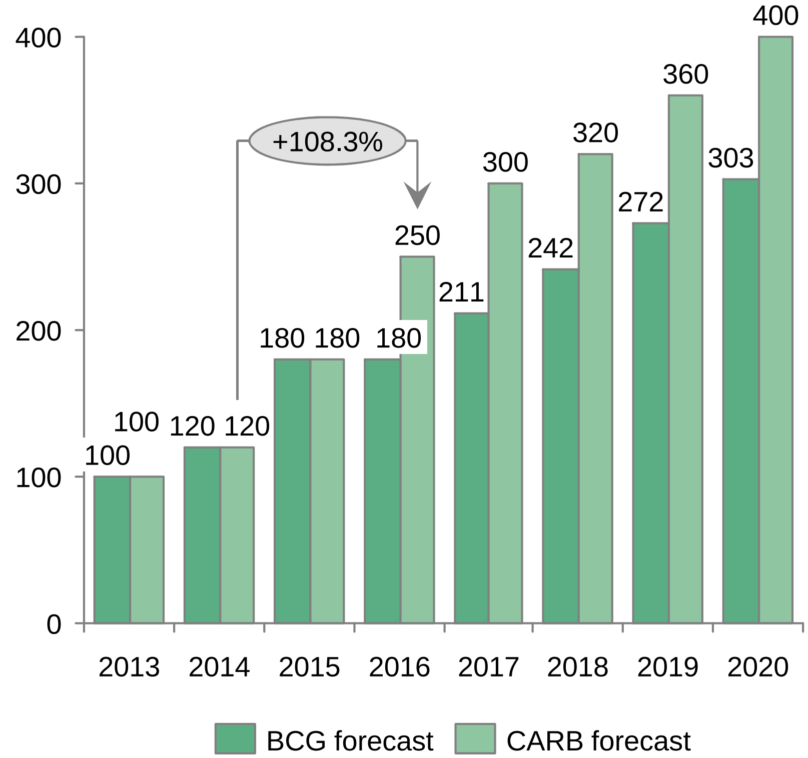
Comparison of BCG and CARB RD volume assumptions

RD volume geneating credits in LCFS (Million gal)



Comparison if RD blending logistical issues are resolved

RD volume geneating credits in LCFS (Million gal)



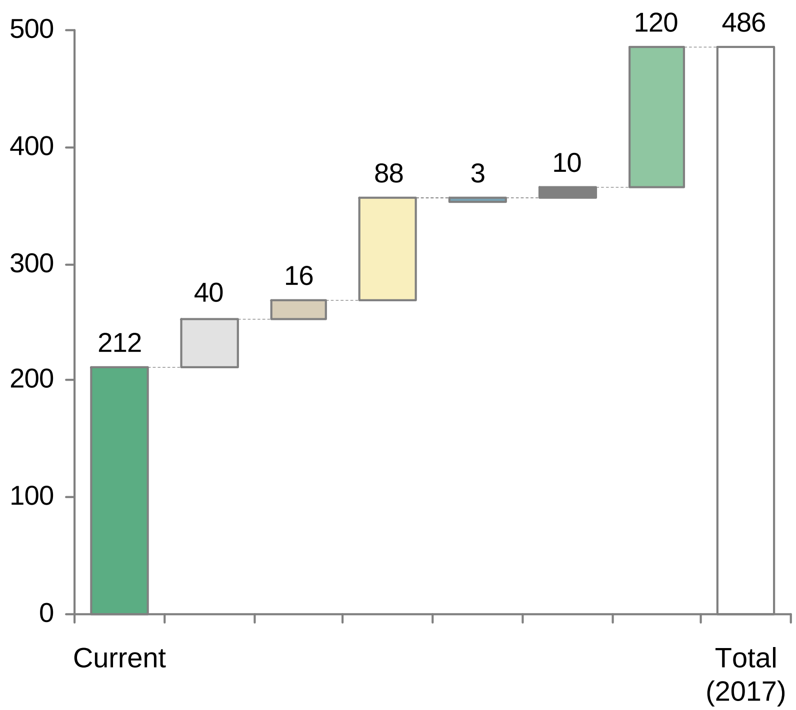
1. Maximum RD reported in any quarter to date is 45 million gallons

Source: CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

Why might available renewable diesel volumes be limited through 2020?

Announced US renewable diesel projects

US renewable diesel capacity (MM gal)



Risk factors for RD availability

Projects not being completed
- 25% of potential US capacity by 2017 is a project announced in summer 2014 with few details
- Some projects being funded with government investment, indicating marginal or worse standalone economics

Fuel under contract
- Some facilities have DOD contracts which will probably limit availability to California

Not all production will be diesel fuel
- Some facilities will produce jet as a portion of their fuel production

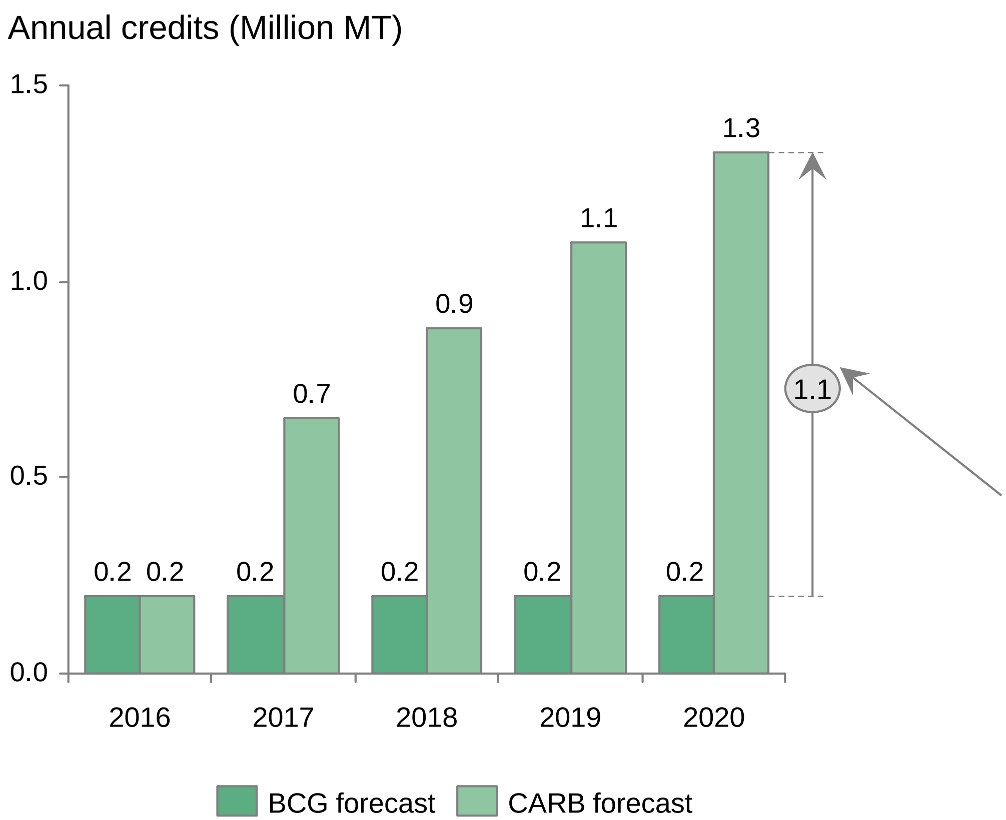
Logistics not in place for fuels to move to California
- At least one Gulf Coast plant does not have ability to move fuel to California

Source: E2, Press search, Biofuels Digest, BCG analysis

2

CARB has introduced new opportunities to generate credits; unlikely to see significant usage by 2020

Comparison of CARB and BCG forecasts for credits from new provisions



Key difference is outlook for "refinery credits"

Off-road electricity
BCG and CARB both include ~0.2 MT per year for fixed guideway transit systems and some off-road vehicles

Innovative production methods
Neither BCG nor CARB assume that any of these production methods will generate credits by 2020

Refinery credits
There are significant regulatory hurdles in getting refining projects approved and relatively low returns for these projects. As a result, BCG blieves that refiners will not have a significant number of qualifying, credit-generating projects by 2020.

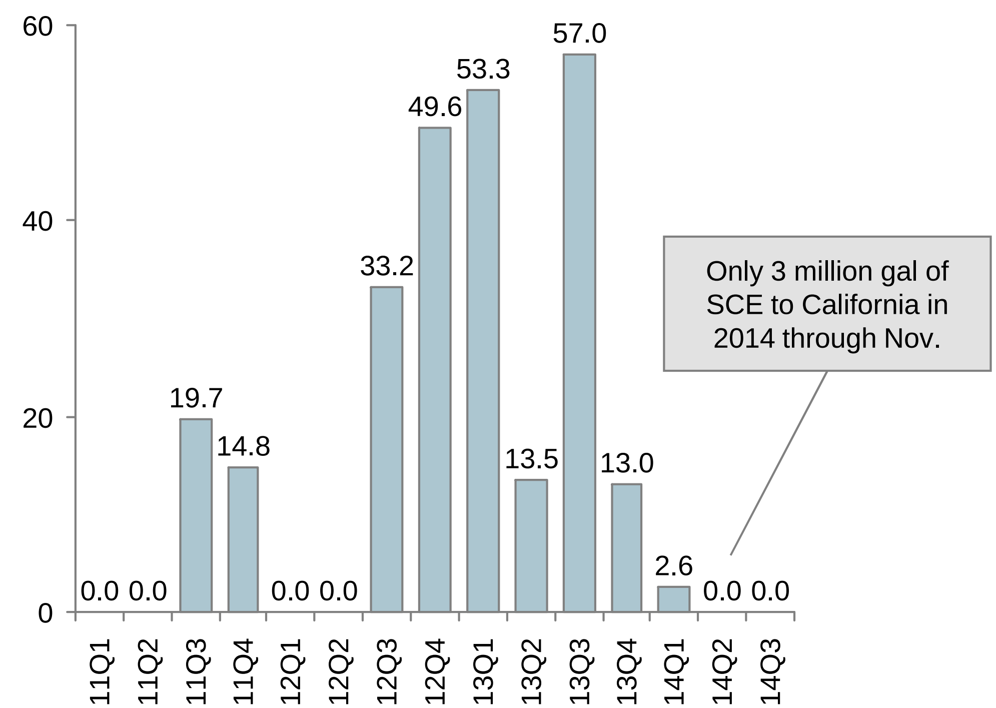
Source: CARB ISOR Appendix B, BCG analysis

CARB forecast for sugarcane ethanol availability optimistic even though imports have fallen dramatically

3

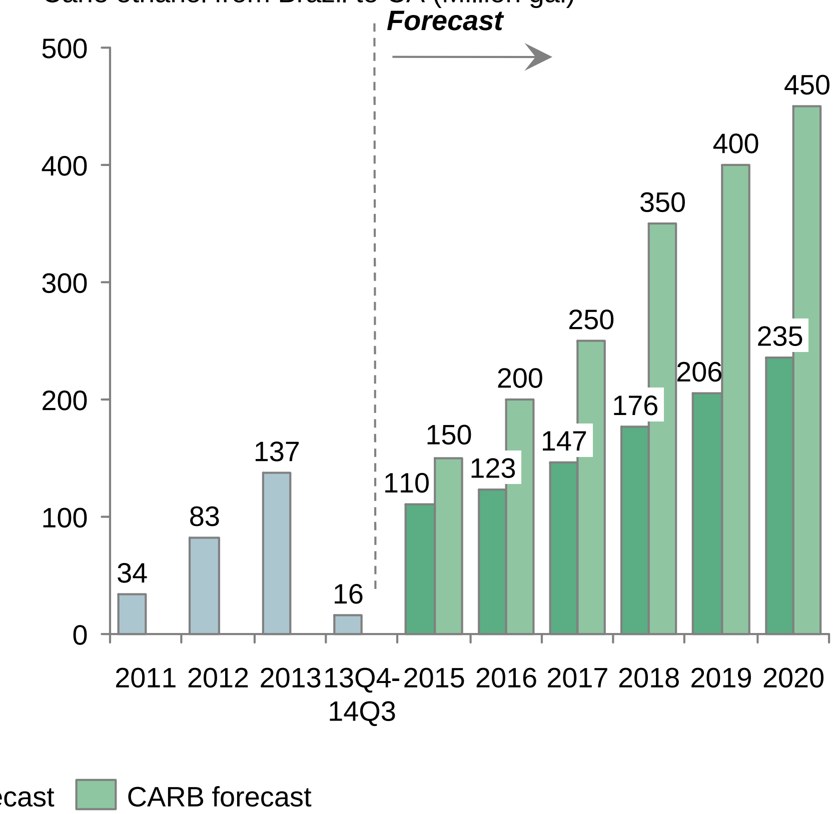
Cane ethanol volumes to CA have been inconsistent, recently zero

Cane ethanol from Brazil to CA (Million gal)



CARB forecast much more optimistic than BCG's expectations

Cane ethanol from Brazil to CA (Million gal)

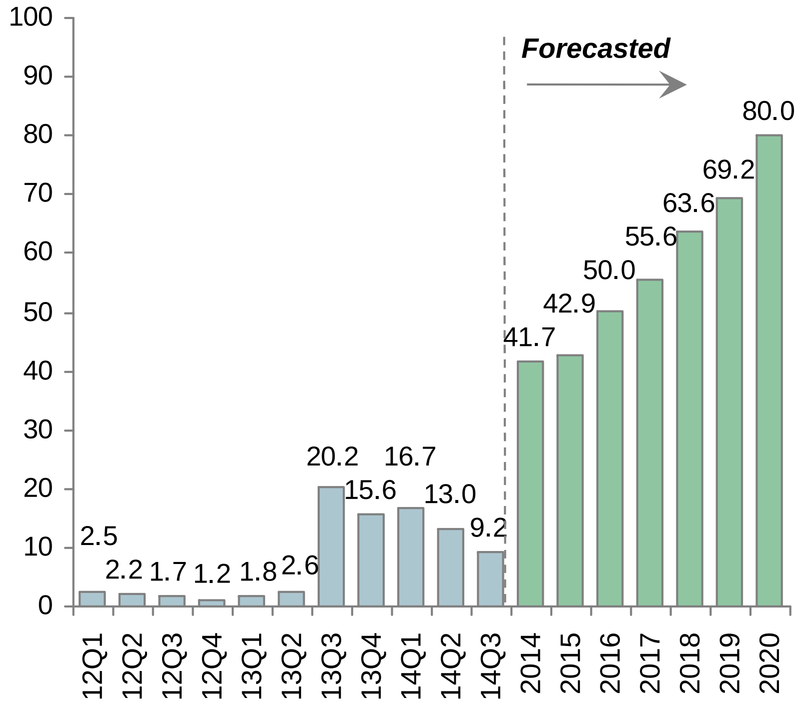


Source: CARB ISOR Appendix B, CARB quarterly LCFS data (as published January 20, 2015), US Census Bureau, BCG analysis

4 CARB renewable natural gas numbers overstated for 2014, likely optimistic for future years

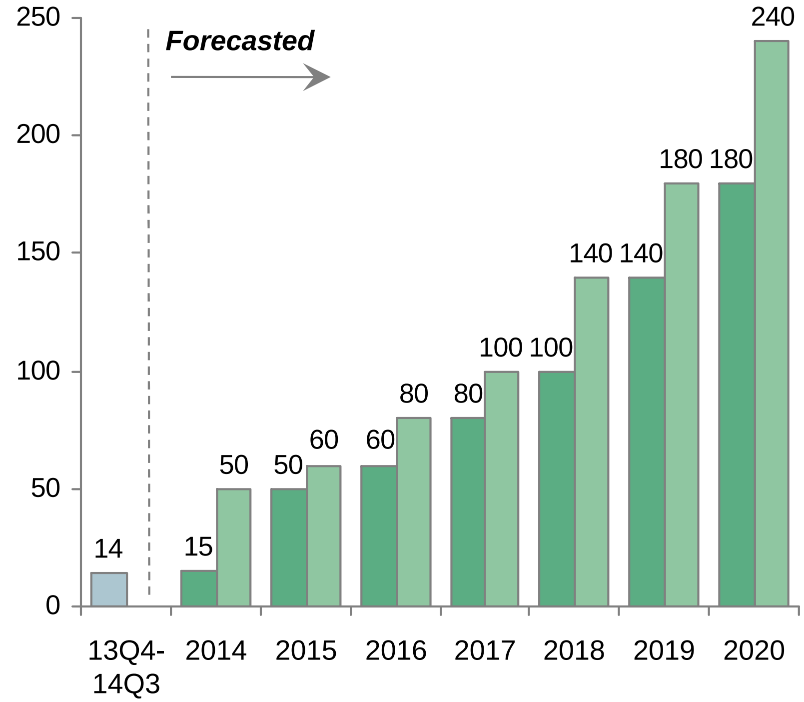
CARB expecting an immediate step change in RNG usage...

Renewable portion of natural gas in LRT[1] (%)



...with 2014-15 volumes 3x that of the last 12 months recorded in LRT

Forecasted NG in LRT (Million dge)



Historical BCG forecast CARB forecast

1. LCFS reporting tool
Source: CARB quarterly LCFS data (as published January 20, 2015)

4 CARB RNG assumptions difficult to assess, pose additional risk to their estimate of available credits

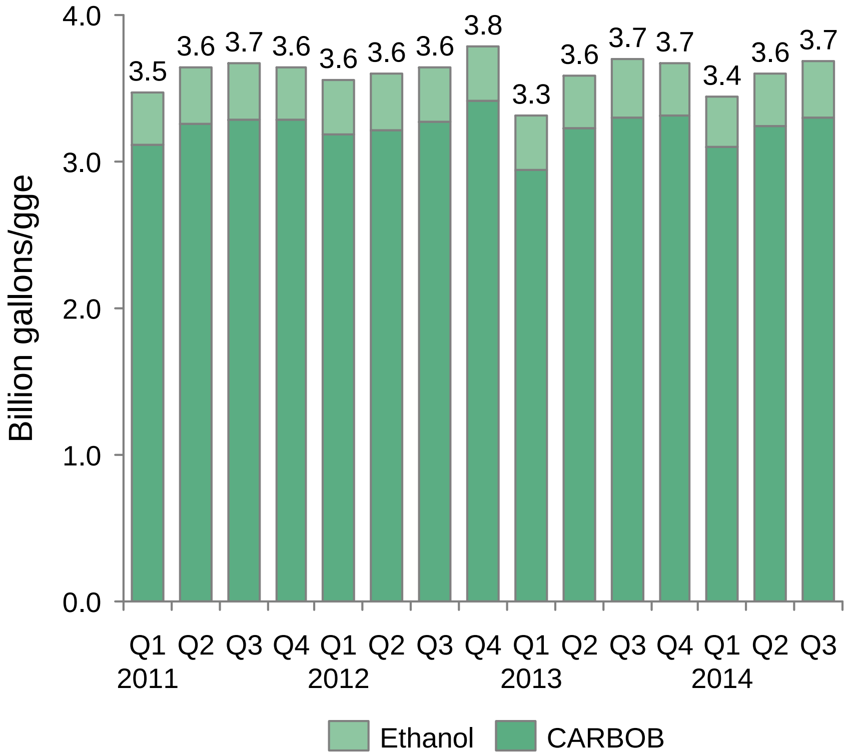
CARB model assumes rapid growth in renewable natural gas usage for transportation

- CARB assumes the share of renewable natural gas of total natural gas volume increases from 10-15% in 2014 to 80% in 2020
- Without access to CARB's market/survey information, BCG has assumed the same growth expected by CARB
  - Because 75% of volumes for 2014 have been reported with no evidence of substantial growth, BCG assumes that the rapid growth starts in 2015 (delays growth 1 year)

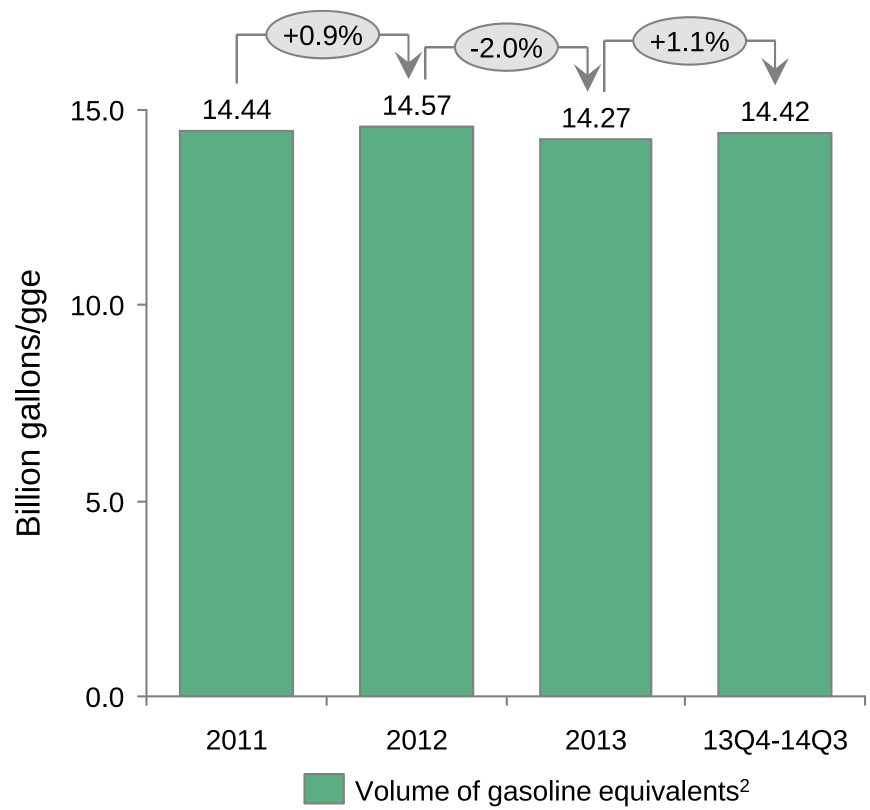
Questionable whether LCFS is incenting production of additional renewable NG or switching renewable NG usage from one sector (utility / power generation) to another (transportation fuels).

5 Gasoline (and equivalents) volumes have been consistent over the first few years of the LCFS

Quarterly volumes of gasoline equivalents from CARB LCFS reporting tool[1]



Volumes have stayed within a relatively small range since 2011

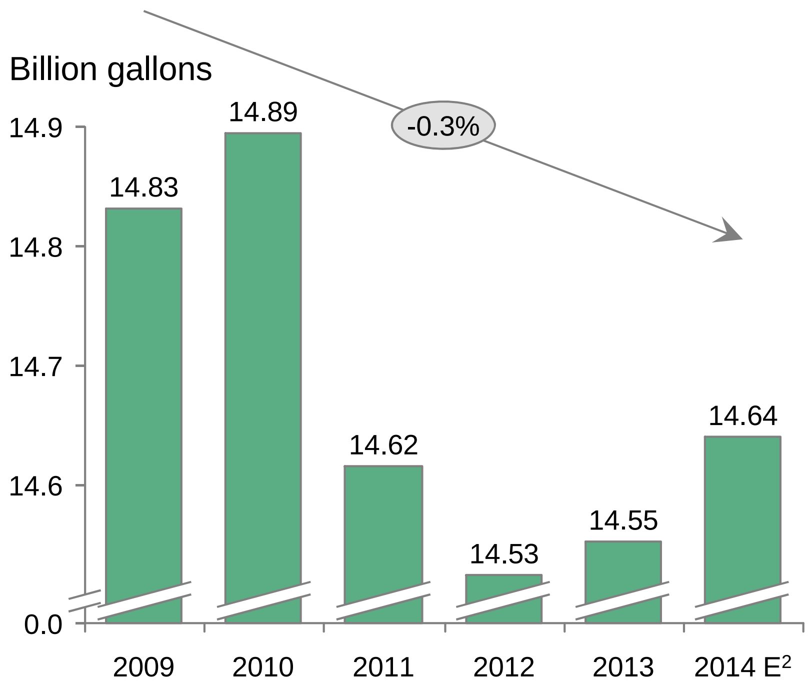


1. Electricity not shown as it accounts for less than 0.01% of gasoline equivalent volume in each quarter 2. Sum of CARBOB, electricity and ethanol volumes
Source: CARB quarterly LCFS data (as published January 20, 2015)

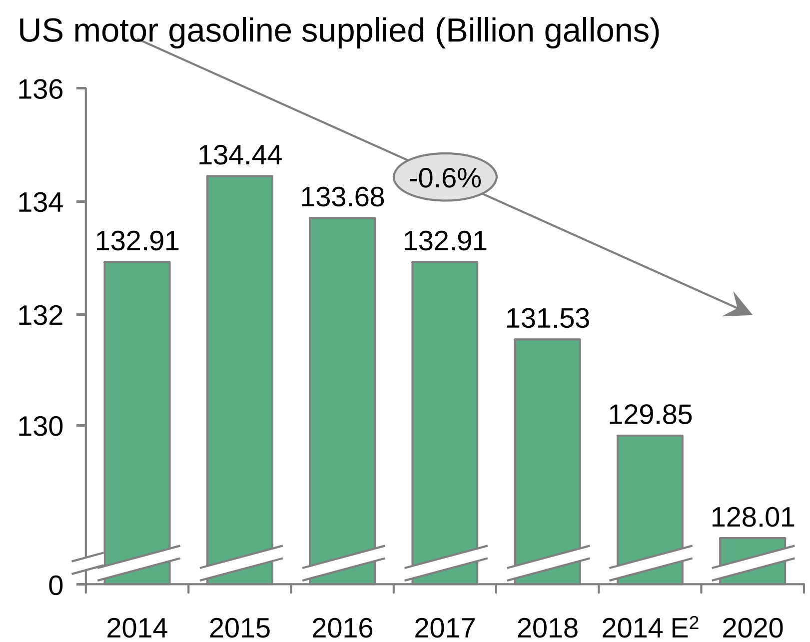
Gasoline blend[1] consumption is expected to continue declining moderately through 2020

5

Gasoline blend[1] consumption in California has declined ~0.3%/yr



EIA forecasts an average decline in motor gasoline supplied of ~0.6%/yr

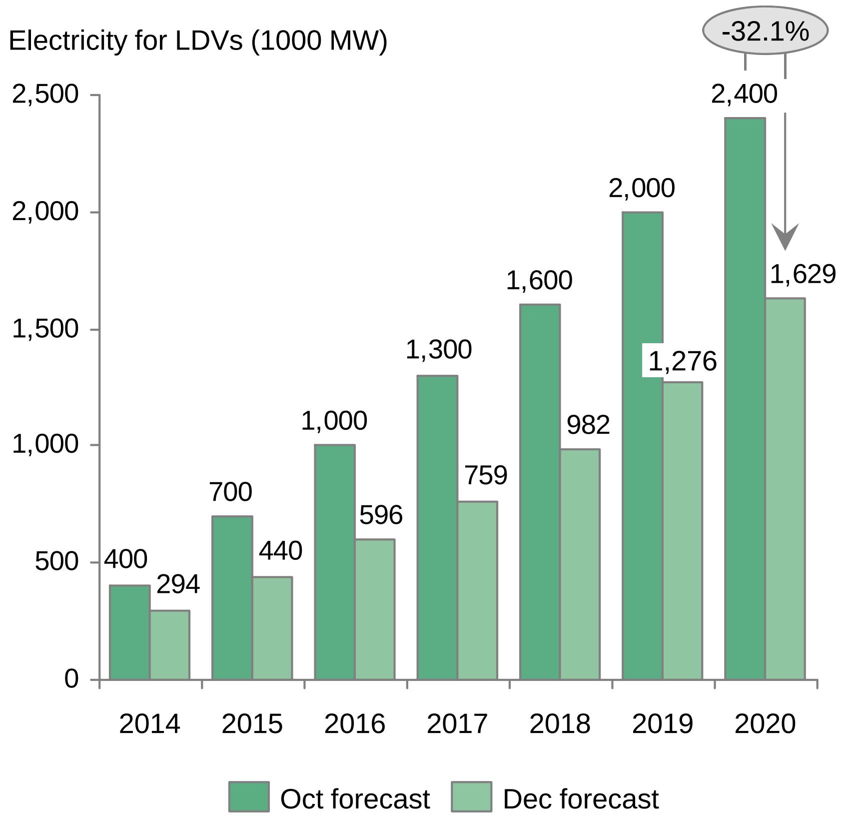


BCG assumes an annual decrease of 0.6% in total gasoline equivalent usage

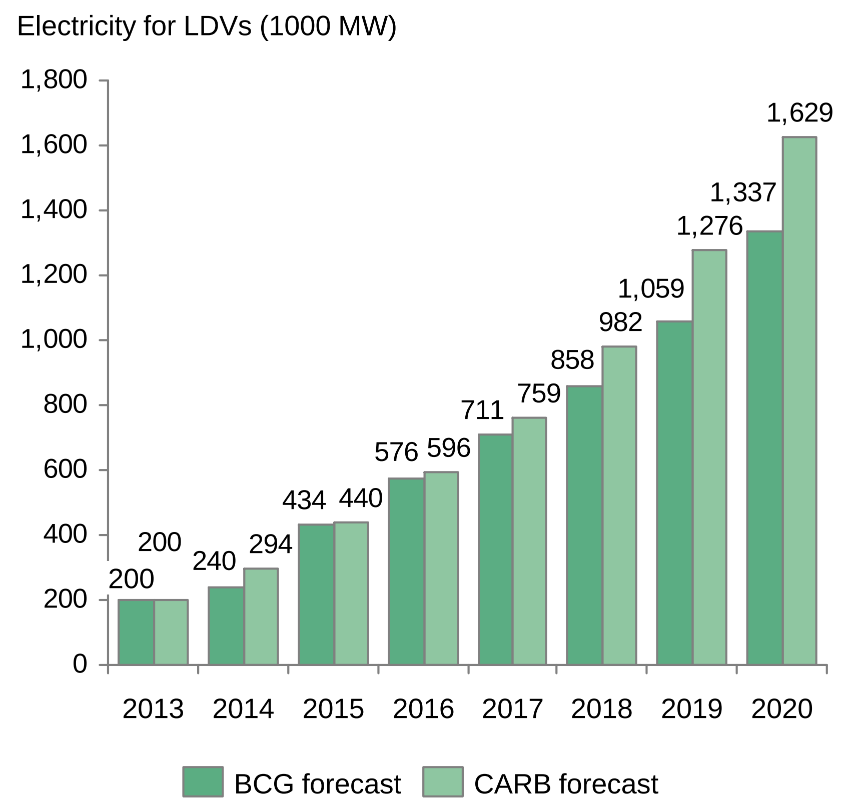
1. Gasoline and gasohol 2. Projected using Jan-Jul 2013 vs. Jan-Jul 2014
Note: Data collected prior to shift in the global crude price may not reflect today's market climate
Source: Federal Highway Administration Motor Fuel Trends

6 CARB has lowered expectations for EV usage since its October workshop

Since October, CARB has tempered expectations regarding EV usage...



...making expectations of EV usage close to those projected by BCG



Note: includes plug-in hybrid electric vehicles (PHEV) as well as battery electric vehicles (BEV)
Source: CARB compliance scenario workshop, CARB ISOR Appendix B

Agenda

Overview

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Methodology for BCG sugarcane ethanol and renewable diesel forecast adjustments

Sugarcane Ethanol

2013
- Used CARB volume

2014
- LCFS data through June 2014 indicates 2.6 MM gal of SCE
- US Census data indicates no further imports of SCE through November 2014
- Assumed limited imports in Dec 2014 (~3 MM gal)

2015-2020
- Started with optimistic (EIA 2014 AEO) and pessimistic (FAPRI) projections of sugarcane ethanol imports to the US. Created a blended projection of 50% EIA and 50% FAPRI.
- Assumed that California could get 25% of US imports in 2015 with increases of 5% each year up to 50% by 2020.
  - Recent high of US share to the US West Coast was ~35%

Renewable Diesel

2013-14
- Used CARB volumes/projection

2015-2016
- Assumed that renewable diesel usage would be limited to 5% of the diesel pool due to logistical issues of supplying blends >5% to market + limited availability

2017-2020
- Assumed that the overall percentage would rise above 5%, ramping up to 6% with isolated usage of R100 or other blends

---

2017-2020 (Sensitivity Case)
- Assumes linear growth in volumes available to California up to a 2020 maximum. This maximum volume includes:
  - 180 million gallons sourced from Singapore
  - California can get 35% of all <u>announced</u> US renewable diesel capacity

Source: California New Car Dealers Association, CARB quarterly LCFS data (as published January 20, 2015), CARB ISOR Appendix B, US Census Bureau, BCG analysis

Methodology for BCG EV and RNG forecast adjustments

EVs

Efficiency
Assumes same increases in efficiency in PHEV/BEV as predicted by CARB in compliance scenario.

Increases in stock
- Recent increases of PHEV and BEV stock (more than 80% for each in 2014)
- Assume continued growth above EIA estimates (low single digit growth in EV stock).
- Assume that stock increases would moderate as existing stock increases and tax credits decrease.
  - Assume 25% stock growth 2015-2017
  - Assume 15% stock growth 2018-2020 as battery costs decline to make EVs marginally more affordable

Renewable Natural Gas

2014
Given progress to date in 2014, assumed that the CARB forecast of 50 million gallons DGE would not be possible in 2014

2015-2020
Used one year delay from CARB to estimate RNG in BCG forecasts (e.g. 2014 CARB RNG forecast = 2015 BCG RNG forecast)

Source: California New Car Dealers Assocation, CARB quarterly LCFS data (as published January 20, 2015), CARB ISOR Appendix B, BCG analysis

Thank you

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